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STUDY OF OPTIMUM PROPELLANT PRODUCTION FACILITIES FOR LAUNCH OF SPACE SHUTTLE VEHICLES

Performed By

UNION CARBIDE CORPORATION

Linde Division

for

National Aeronautics & Space Administration
John F. Kennedy Space Center
Kennedy Space Center, Florida

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I. INTRODUCTION

The objective of this study is to develop information pertaining to an integrated propellant manufacturing plant and distribution system located on and meeting the needs of the John F. Kennedy Space Center (KSC) in carrying out the requirements of the Space Shuttle Program.

At the outset of this study, the planned propellant and pressurant production for the Space Shuttle mission ammounted to 160 tons/day liquid hydrogen, 10 tons/day gaseous hydrogen, 800 tons/day liquid oxygen, 400 tons/day liquid nitrogen, and 120 tons/day gaseous nitrogen. This was based on a shuttle launch frequency of 104 per year. During the course of the study, two developments occurred which may lead to lowered cryogen requirements than those stated above. First, detailed investigation of transportation losses indicated that a facility producing approximately 125 TPD LH_2 and corresponding other fluids could meet the requirement of 104 shuttle launches per year. Secondly, a maximum shuttle launch frequency of 50 per year rather than 104 is now considered more probable. Bearing this in mind, the study is primarily addressed to the problem of supplying the large 160 TPD LH_2, etc. propellant and pressurant requirements, however it is sufficiently flexible to permit making an analysis at practically all levels of production.

A variety of plant and processing equipment sizes and costs are considered in this report for both redundancy and supply level considerations for an integrated propellant manufacturing facility. Steam reforming is compared against partial oxidation as a means of generating hydrogen. Electric motors, steam turbines and gas turbines are evaluated as prime movers for driving compression equipment. Various sites both on and off Government property, are considered to determine trade-offs between costs and problems directly associated with the site, product delivery and storage costs, raw material costs and energy costs. To affect additional economies, co-production of other products such as deuterium, methanol and ammonia are considered.

Location on Government property raises legal questions which will be discussed concerning a private company's liabilities and its rights to market commercial products under Government tax and cost shelters.

In order to facilitate the presentation, the report is divided into two major sections. The first section will present basic data, costs and other general information. The second section presents an economic analysis and interpretation of the information presented in the first section. In addition, a legal discussion concerning the location of an integrated propellant producing facility on Government property is provided.

II. CONCLUSIONS AND RECOMMENDATIONS

1. The most likely production facility to generate the basic product requirements of this study of 160 tons/day LH_2, 10 tons/day GH_2, 800 tons/day LOX, 400 tons/day LIN, and 120 tons/day GN_2 is an integrated plant using naptha as feed to a steam reformer process for generating hydrogen. Either gas turbines using fuel oil or electric motors would be used to drive compression equipment, dependent on the relative energy costs and contract life. A crew of 66 men would be required if electric motors were used. Eight additional men would be needed for the gas turbine drive case. A 27-month period would be required to design and construct the facility. Land requirements are 75 acres.

2. The most significant factors in obtaining low annual propellant costs for the Cape Kennedy launch complex are dependent upon obtaining and utilizing large scale facilities and contracting for the use of these facilities over as long a period as possible.

3. The integration of cryogen production facilities achieves about 5% cost saving in liquid hydrogen if all such savings are taken to the benefit of liquid hydrogen.

4. Site selection in the Cape Kennedy locale is not significant in cryogen costs compared to the factors mentioned above. A large, well utilized facility with non-interference by Government operations would be favored in a site adjacent to the launch complex. Smaller or less fully utilized facilities would be better located off Government property. If the Government desires to locate this facility on Government property near the launch pad, the attendant risks are considered too great for private industry to incur and should be Government owned and private industry operated. If the facility is located off Government property, then it would be most advantageous to the Government if the facility were owned and operated by private industry.

5. Deuterium is the most interesting co-product opportunity and should be considered if a relatively high level of LH_2 productivity is assured. Since its only market is also Government purchase, it can be produced on either an off-site or on-site facility. Co-product petrochemical manufacture is difficult because of the variable market conditions that exist for products with a synergistic relationship to liquid hydrogen-oxygen. Of the possible candidate materials, methanol would be the most likely to produce sufficient economic return to warrant consideration in a propellant production complex located in Florida.

6. Natural gas at current prices would be the preferred fuel and feedstock. However, insufficient reserves preclude it from being considered as the long range dependable supply. Foreign naptha is the most likely alternative for feedstock, with fuel or crude oil being the least desirable and utilized only on the unavailability of naptha or natural gas. For fuel, fuel or crude oil would be the most attractive alternative in lieu of natural gas. LNG is too expensive to benefit the project and supply uncertainties further preclude consideration as a feedstock or fuel.

7. High investment, low operating cost, gas turbine prime movers tend to be favored in large, highly utilized production facilities, whereas electric motors are favored in smaller or poorly utilized plants. Steam turbine drives are not attractive throughout all utilization ranges. Selection of the prime movers to be used will depend on the relative cost of fuels at the time the plant is designed and the contracting method selected.

8. Steam reforming is the preferred process for the generation of hydrogen. Partial oxidation can only be considered in the absence of an assurance that foreign naptha cannot be made available to the project for the long term.

9. Because of significant economies of scale that are available in this cryogenic complex, storage should be considered to be the prime method of redundancy as opposed to parallel train operation.

10. Evaluation of the Minimum Requirements Option on the criteria baseline for this study indicates that a 170 ton/day hydrogen plant would be required in 1978. More detailed evaluation of the loss criteria employed in defining this study indicated, however, that the complex need not exceed 125 tons a day. Evaluation of a 50 annual launch option indicates that relocation of the existing 60 TPD LH_2 facility in 1980 is most attractive, whereas, evaluation of a revised Minimum Requirements option indicates that this plant should be relocated in 1975.

III. DISCUSSION

A. Investigation of Basic Design Data and Costs

The purpose of this study is to determine the lowest cost means for propellant and pressurant production and supply at Kennedy Space Center (KSC) in support of NASA's Space Shuttle mission. This entails determining the value of building an integrated production facility over non-integrated facilities to produce the desired amounts of oxygen, nitrogen and hydrogen products. Processing equipment sizes and costs for both redundancy and supply level considerations need to be considered. Steam reforming, either natural gas or naptha, is generally a less expensive route to generating hydrogen than is partial oxidation of naptha or fuel oil. However, if natural gas is not available and naptha is more costly than fuel oil (which cannot be processed through a steam reformer), will partial oxidation prove more attractive? Also, how much does the capability for marginal or incremental production of oxygen in an integrated production facility such as this improve the relative economics of the partial oxidation process? The best of three possible prime mover systems - electric motors, steam turbines, and gas turbine and steam turbine combinations - for driving the compression equipment needed to generate refrigeration for liquefying the oxygen, nitrogen and hydrogen products must be selected based on initial investment and operating costs. These operating costs will be strongly influenced by the availability and cost of various forms of energy in the KSC area. Co-production of products such as deuterium, methanol, ammonia and/or commercial liquid hydrogen, oxygen and nitrogen may effect additional economies to reduce propellant production costs. Location of the production facility on government property as near the shuttle launch pad as safety criteria will permit would enable delivery of propellants and pressurants by pipeline. The cost of this method of delivery must be compared with other delivery means such as trucks, rail and barge from sites which could be located either on or off government property. The initial phase of this study was directed toward development of cost data for the various production, delivery and site alternatives described above.

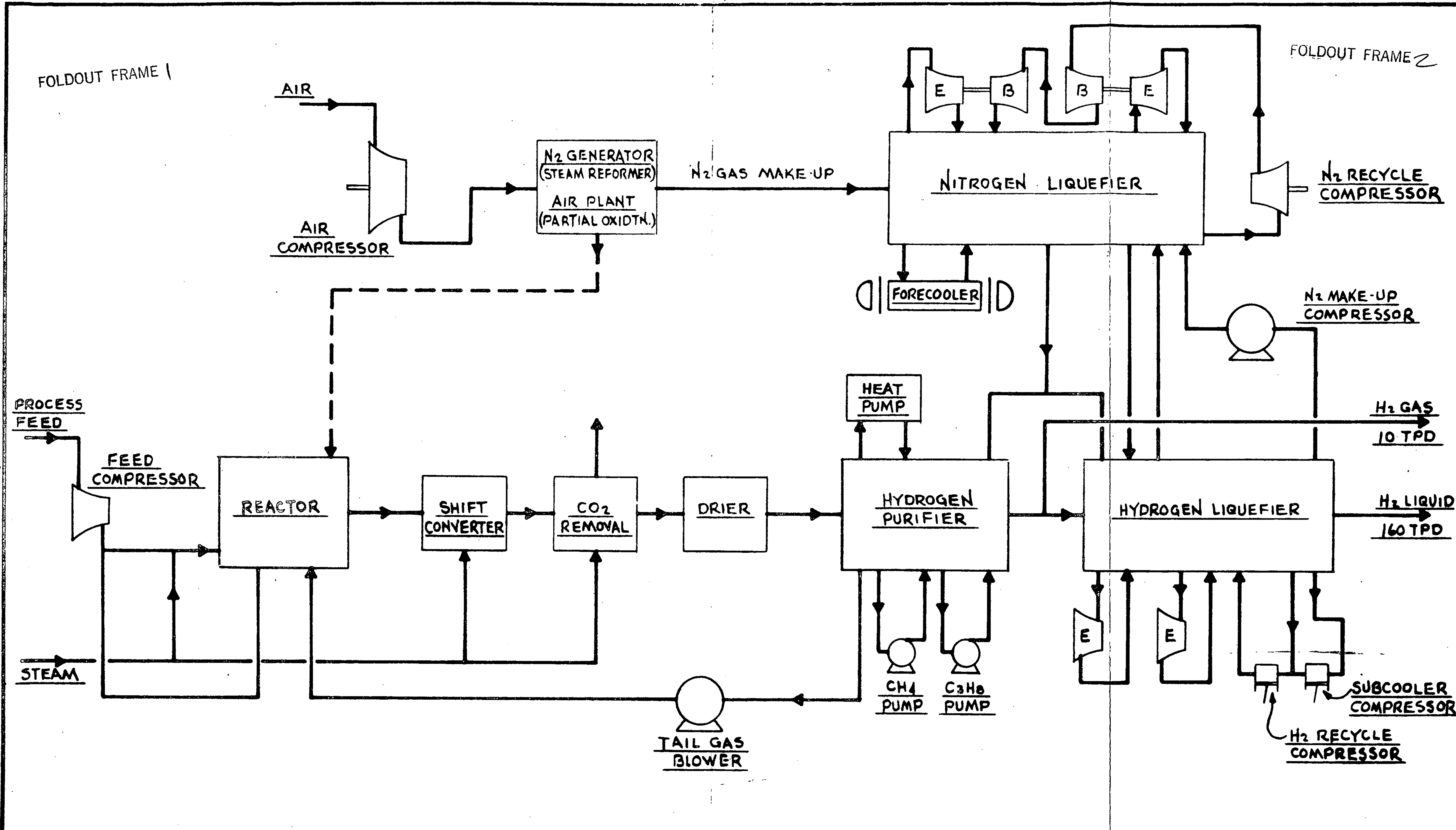
Turnkey costs were developed for each plant design concept. Turnkey costs include engineering, plant site purchase and preparation, process equipment, construction, a minimum plant storage capacity of 2-1/2 days production, distribution facilities, plant checkout and startup and interest and taxes paid during construction and startup.

1. Propellant Manufacturing Plant

a. Non-Integrated Plant

Liquid Hydrogen Plant

The process employed for the non-integrated liquid hydrogen plant is presented by Figure 1. Hydrogen is produced by catalytically reacting a



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Title: NON-INTEGRATED HYDROGEN PLANT PLUS LIQUEFIER

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FIGURE 1

hydrocarbon feed such as natural gas or naptha with steam in the case of a steam reformer based process. In the event partial oxidation is used the reaction is a non-catalytic one between a hydrocarbon feed, steam and oxygen. As will be shown later, the partial oxidation process is more costly in terms of initial investment than the steam reforming process, principally because of the oxygen requirement. However, it can handle more severe forms of hydrocarbons such as heavy fuel oil or crude oil which could not be processed in a steam reformer because they would rapidly reduce the activity of the catalysts employed. If the heavy oils are sufficiently less expensive than the lighter hydrocarbon fuels which can be handled in the steam reforming process, the partial oxidation process may be less costly on an evaluated cost basis.

After this initial reaction which produces a mixture of hydrogen, carbon monoxide and carbon dioxide, the reactant products are cooled and processed through a catalytic shift converter which reacts the bulk of the carbon monoxide with steam to produce additional hydrogen and carbon dioxide. The process stream is then cooled to near ambient temperatures where the carbon dioxide is removed by an absorption wash step and then water is removed by molecular sieve adsorption. At this point, the process stream is prepared for cryogenic processing to remove trace amounts of carbon monoxide, nitrogen and unreacted methane. (Note that even in the case of heavy hydrocarbon feedstocks, methane will be the only remaining unreacted hydrocarbon. This is because of the high temperature or catalytic condition of the initial cracking processes).

Nitrogen and carbon monoxide are removed by liquid methane absorption after the process stream is cooled to cryogenic temperatures. Methane is next removed by absorption with subcooled propane.[1] After this step, the process stream consists of hydrogen with trace quantities of propane which are removed by adsorption on activated carbon. Refrigeration needed for the cryogenic purification steps is principally supplied by liquid nitrogen which is generated by a nitrogen liquefier. Makeup for nitrogen leakage, primarily from the nitrogen recycle compressor, is provided by a nitrogen generating plant when a steam reforming process is used and by the air separation plant when partial oxidation is used.

After purification, the hydrogen can be liquefied. This is accomplished by use of liquid nitrogen forecooling to cool to the temperature of liquid nitrogen then compression and expansion of recycled gaseous hydrogen to cool and liquefy the hydrogen. With the exception of the reciprocating hydrogen recycle compressors, all process functions can be handled by single components at the 160 TPD liquid hydrogen production level without extending the state-of-the-art equipment technology. Three reciprocating hydrogen recycle compressors are needed in parallel to provide the necessary compression energy to liquefy hydrogen.

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(1) Baker, C. R. and Paul, R. S., "Process and Apparatus for Purifying Gases", U.S. Patent No. 3,073,093.

Air Separation and Liquefaction Plant

The process employed for the non-integrated air separation plant is presented by Figure 2. Air is compressed, cooled and then separated in the double distillation columns in a standard air separation process.(1) The 800 TPD oxygen and 520 TPD nitrogen requirements are well within the production capability of a single train air plant. Refrigeration needed to cool and liquefy the separated nitrogen and oxygen products is generated by means of a nitrogen liquefier. This is accomplished by transferring saturated nitrogen vapor from the top of the lower of the double distillation columns in the air plant to the nitrogen liquefier. Here the nitrogen is liquefied by heat exchange against recirculated nitrogen which is compressed and then cooled by expansion through a turbine expander. The liquefied nitrogen product is then returned to the air separation plant where a portion is heat exchanged against oxygen vapor to produce the required oxygen liquid and both cryogens are subcooled to minimize product flashoff loss during transfer to storage.

b. Integrated Plant

The process developed for the integrated propellant manufacturing facility is presented by Figure 3. A typical plot is presented by Figure 4. Approximately 75 acres would be required for the integrated cryogen producing facility. The same basic systems described for the non-integrated hydrogen generation and air separation plants were employed. The main process area where investment cost reductions could be realized when integrating the separate facilities together was the nitrogen refrigeration system. One nitrogen liquefier cold box can be used as opposed to two in the non-integrated case and a single, large nitrogen recycle compressor, requiring approximately 50,000 horsepower at maximum production output, can be employed without extending state-of-the-art equipment technology. Similarly, integration of the separate steam and gas turbine drive systems resulted in lowered costs. Other major areas where integration proved beneficial in terms of cost reduction were site preparation, cooling water supply, elimination of the nitrogen generation facility in the case of steam reformer generation of hydrogen and integration of separate oxygen plants in the case of generation of hydrogen by partial oxidation.

As will be shown later, power and energy requirements were reduced slightly by virtue of the fact that larger, more efficient compression equipment could be employed in the nitrogen refrigeration loop. Similarly, the efficiencies of both the gas and steam turbine power cycles improved due to the integration because a more efficient process could be justified and larger, more efficient equipment could be employed.

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(1) Latimer, R. E., "Distillation of Air", Chemical Engineering Progress, February, 1967, pgs. 35-59.

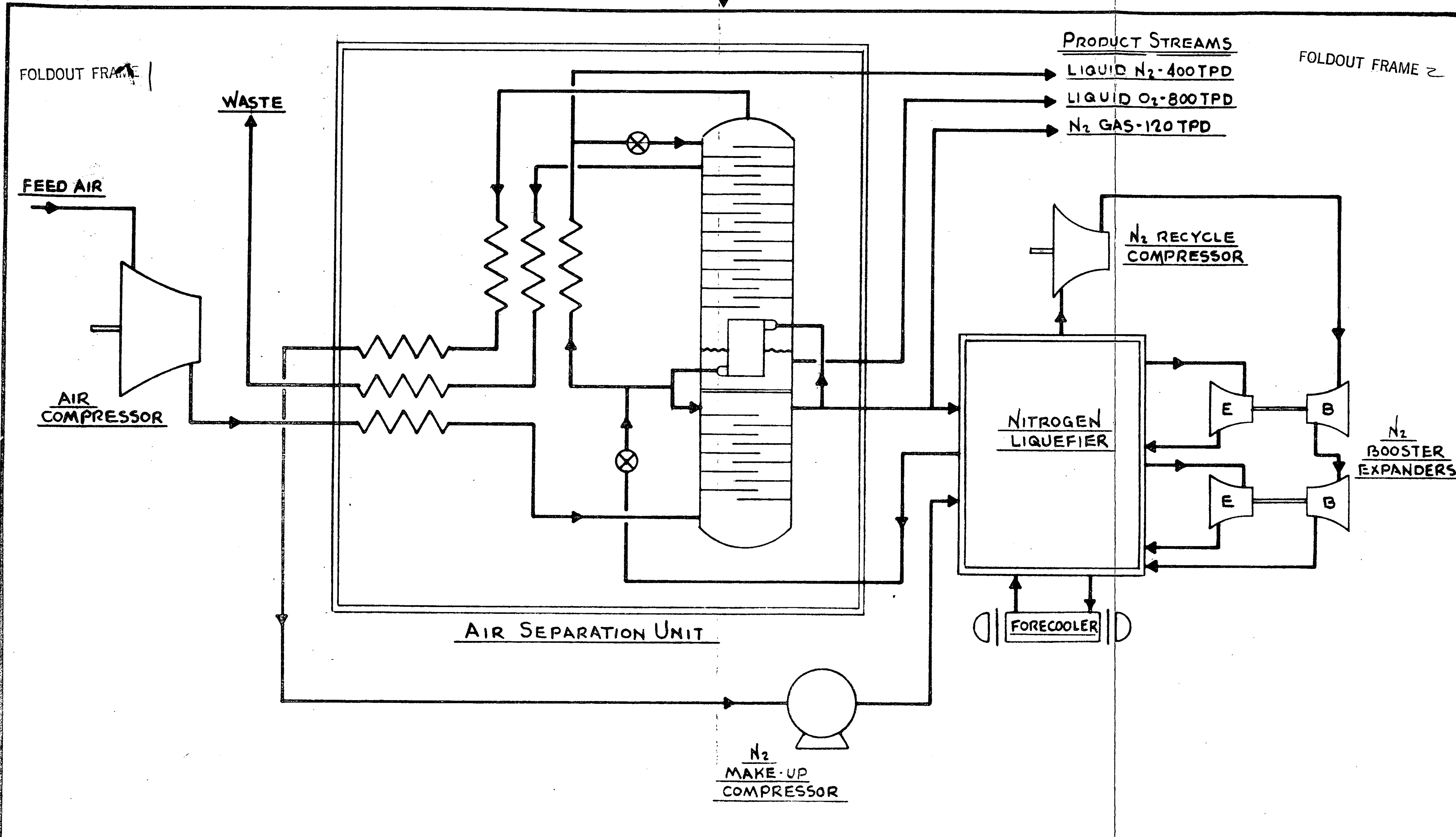

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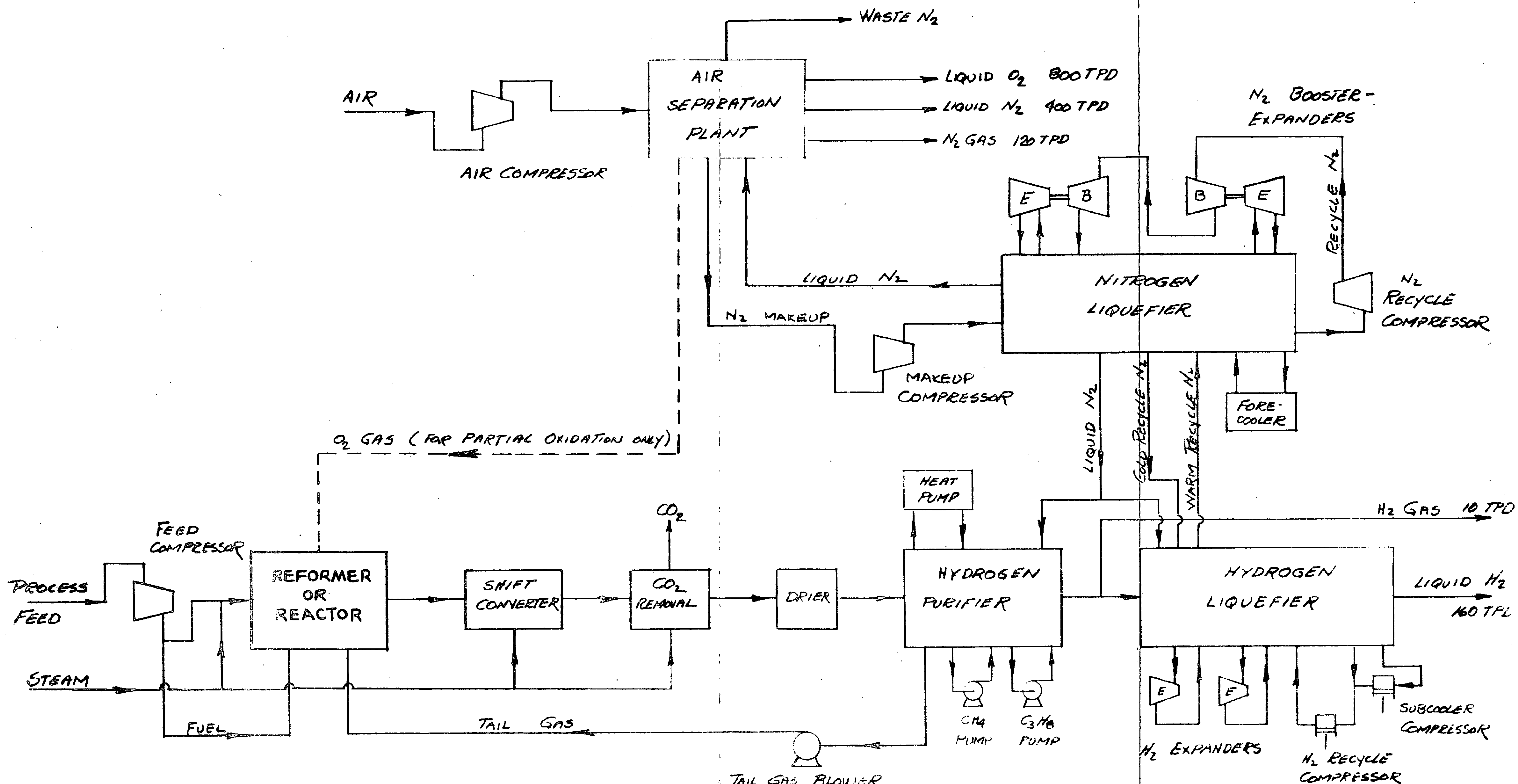
FIGURE 2

FOLDOUT FRAME 1

FOLDOUT FRAME 2



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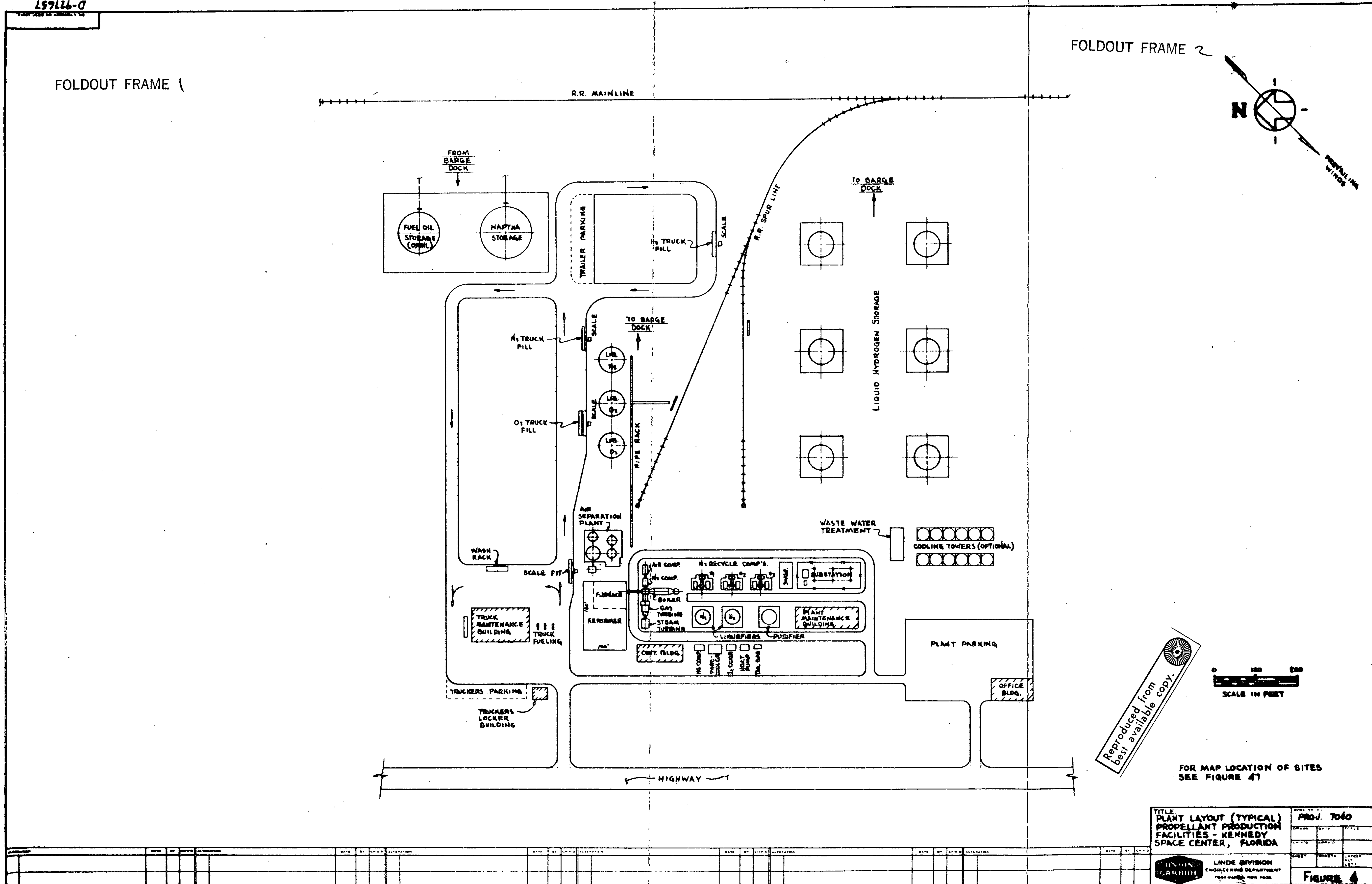
UNION CARBIDE CORPORATION **LINDE DIVISION** ENGINEERING DEPARTMENT - TONAWANDA, NEW YORK	D'WN 5-18-70	FIGURE-3
Title: BLOCK FLOW DIAGRAM - INTEGRATED LIQUID PROPELLANT MANUFACTURING PLANT	C'KD CRB	SHEET No. 1
	APP'VD CRB	of 1 SHEETS



FOR MAP LOCATION OF SITES SEE FIGURE 47

TITLE
PLANT LAYOUT (TYPICAL) PROPELLANT PRODUCTION FACILITIES - KENNEDY SPACE CENTER, FLORIDA

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FIGURE 4

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c. Safety Considerations

The two major safety hazards facing an integrated cryogen producing facility such as this are (1) fires caused by accidental hydrogen or hydrocarbon spills or venting and, (2) air separation plant explosion caused by intake of accidentally vented hydrocarbon in the feed air. Careful consideration has been given to plant design and layout to minimize the risks from these hazards.

Location of bulk product H_2 storage (refer to plot plan) was determined by using National Fire Protection Association (NFPA) - 50B as a guide. The million gallon liquid hydrogen storage tanks are separated by 170 feet from each other, and 440 feet from the LOX tanks. Each liquid hydrogen tank is surrounded by a dike capable of containing its contents. Failure and combustion of the contents of any one of the tanks would not seriously damage, or cause failure of, an adjacent tank. The liquid hydrogen fill zone is located 200 feet from the closest liquid hydrogen tank. The potential for accidental spills and fires are greater in this area than in any other part of the plant. Distance from adjacent tankage and equipment eliminates the probability that fire in this area would cause extensive plant damage. The fill zone would also be provided with an automatic water quench system.

The liquid oxygen and fuel oil tankage were located using NFPA-566 and 567 as a guide.

As a precaution against hydrocarbon input to the air separation plant, the air compressor intake is located at the upwind side of all hydrocarbon processing and storage equipment. In addition, the air separation unit itself is provided with hydrocarbon removal systems capable of extracting dangerous hydrocarbon materials from industrially polluted feed air.

d. Ecology Considerations

Basically, a cryogen producing facility is quite clean and its pollution effects are minimal. Thermal pollution is the primary concern. Cooling water is required to remove heat from process streams that have been compressed and in the case of the gas and steam turbine drive systems, remove low grade heat energy which cannot be effectively converted to mechanical energy. Care must be taken not to permit this water temperature to exceed 90°F to avoid potential thermal pollution problems if raw water is used on a straight through flow basis. This is avoided by using a sufficiently high quantity of water.

Noise levels from compression equipment could present a minor problem if it proved necessary to locate near a residential area. A minimum distance of 2,500 feet between such an area and the production plant is generally recommended. This should not prove to be a problem based on the sites being considered which will be discussed later.

The only other potential source of pollution would be from sulfur which may be contained in the hydrocarbons being used as process feed or fuel. This is minimized by specifying and purchasing low sulfur containing fuel. Also, any sulfur contained in the process feed stream is removed either by adsorption, in the case of the stream reformer process, or absorption in the case of the partial oxidation process.

e. Summary of Estimated Plant Costs

Investment costs for the basic production requirements of this study for 160 TPD LH_2, 10 TPD GH_2, 800 TPD LOX, 400 TPD LIN and 120 GN_2 are summarized by Figure 5, appended, for both non-integrated and integrated plant cases for the various combinations of electric motor, gas turbine and steam turbine prime mover systems, steam reformer hydrogen generation systems generating hydrogen from pipeline natural gas, liquefied natural gas and naptha, and partial oxidation hydrogen generation systems generating hydrogen from both naptha and crude oil. These costs are also presented graphically, as a function of plant capacity to provide costs for intermediate plant sizes, by Figures 6 to 20, appended. For the integrated cases presented, a product ratio of 160 TPD LH_2, 800 TPD LO_2 and 400 TPD LN_2 was employed. Thus, the investment represented by 80 TPD LH_2 would include 400 TPD LO_2 plus 200 TPD LN_2 production capability.

In addition, use of LNG for both feedstocks and fuel was investigated for the integrated plant case. Refrigeration from the LNG can be utilized as a forecooling fluid in the integrated nitrogen refrigeration loop to reduce power consumption and investment in the cold box. Total investment for an LNG based hydrogen plant cannot be reduced below that of a pipeline natural gas based hydrogen plant however, because of the necessity for LNG vaporization during plant startup. Energy consumption will be reduced by use of LNG and this will be presented below.

f. Plant Utilities

Electric and fuel requirements for the basic propellant production requirements of this study are summarized by Figure 21, appended, for the same cases for which investment costs were summarized above. In all cases, electric drive has been used for the reciprocating hydrogen recycle compressors. This is because gear requirements for speed reduction in the case of gas and steam turbines would present nearly impossible mechanical problems. Gas engines could be considered, however, this is precluded by the high maintenance costs and initial investment charges compared with electric motors. Also, these requirements are presented graphically, as a function of plant capacity for the purpose of determining costs for intermediate plant sizes, by Figures 22 to 36, appended. Figures 37 and 38, appended, present similar information for a process based on using LNG as a feedstock.

The fuel needed for process feed is the same for corresponding integrated and non-integrated cases for both the steam reformer and partial oxidation hydrogen generating processes. Similarly, the electric power requirement is the same for all steam and gas turbine prime mover cases, consisting of the power required for the reciprocating LH_2 cycle compressors, plus a small amount of miscellaneous power for items such as lighting, process controls and small motors.

Total manpower requirements for operating and maintaining the integrated facility based on using all electric drive amount to 66 persons. This breaks down into four operating crews of seven men each plus five maintenance men per shift and a foreman for each shift or operating crew. In addition, nine office personnel, a quality assurance person, two foremen supervisors, plus a plant superintendent and an assistant are required. Gas and steam turbine drive based plants will require one additional operator and an additional maintenance man for each shift. It is emphasized that this is personnel required for plant operation and that additional people will be needed for product distribution. This requirement will vary depending on the type of distribution system used.

g. Equipment Reliability and Redundancy

Costs and utility requirements presented above are based on a single train process with the exception of the three parallel reciprocating hydrogen recycle compressors. Such a process will have the lowest investment and operating costs possible, however, it will also have the lowest reliability because a failure of one component in the train will lead to plant outage. Reliability can only be increased by increasing investment costs and this is the tradeoff which must be faced. Data for evaluating three of the most significant possible tradeoffs, those being duplicate half-sized single train systems, half-sized equipment within the single train system and additional storage is provided below.

1. Duplicate Half-Sized Single Train Systems

Data presented here will be made for the steam reformer hydrogen generating process using naptha as feed and electric motors for prime movers. Comparisons based on the other process alternatives for which investment and operating costs were presented above will be quite similar. Investment and operating cost premiums for two half-sized single train systems are as follows:

INVESTMENT

Plant Type	Single Train	Two Half Single Trains	Investment Premium
Non-Integrated Air Plant plus Liquefier	\$ 8,300,000	\$11,300,000	\$ 3,000,000
Non-Integrated LH_2 Plant	34,300,000	45,900,000	11,600,000
Integrated Plant	39,980,000	52,980,000	13,000,000

UTILITY REQUIREMENTS

Plant Type	Single Train Electricity-KW	Single Train Fuel Btu/Hr x 10^{-6}	Two Half Single Trains Electricity-KW	Two Half Single Trains Fuel Btu/Hr x 10^{-6}
Non-Integrated Air Plant plus Liquefier	28,800	-	29,500	-
Non-Integrated LH_2 Plant	83,100	1,250	84,400	1,270
Integrated Plant	110,800	1,250	112,800	1,270

Two half-sized plants do have the advantage that they could be installed at different times during the space shuttle program as the propellant requirements gradually build up, thus saving interest on the initially unused portion of investment in a larger plant. However, this advantage is likely to be offset by inflation effects.

2. Half-Sized Equipment Within a Single Train System

Some redundancy can be provided by selecting key items within the single train process and replacing it with parallel half-sized units. At the extreme, this approach would be identical to the two half-sized plant scheme described above. Cost premiums for providing redundant components in this manner are listed in the most probable order of their being critical to the system as follows for the 160 TPD integrated propellant manufacturing facility.

Component	Premium for half-sized Redundancy
1. Nitrogen Recycle Compressor	
a. Electric Drive	$ 420,000
b. Steam Drive	490,000
c. Gas Turbine Drive	580,000
2. Hydrogen Generation Unit	
a. Steam Reformer	2,500,000
b. Partial Oxidation	3,500,000
3. Air Separation Plant Compressor	
a. Electric Drive	320,000
b. Steam Drive	360,000
c. Gas Turbine Drive	360,000
4. Hydrogen Expansion Turbine	180,000
5. Hydrogen Purifier Cold Box	1,200,000

3. Added Storage

As stated previously, the production plant costs presented earlier included storage for 2.5 days of production. Added storage will certainly improve the ability of a facility such as this to provide product when needed during periods of plant outage. A review of the performance of Linde's 60 TPD LH_2 plant in Sacramento, California and 30 TPD LH_2 plant at Ontario, California indicated that maximum plant outage due to malfunction of process equipment was ten days. Based on this rather limited amount of data, it would appear that this should be considered a minimum storage requirement in order to guarantee product availability in the event there is no product equipment redundancy. Costs for this amount of storage can be determined by information provided in Section III, A 4.a. below.

h. Incremental Product Purity and Production Rate Alternatives

1. Decreased Nitrogen Purity

Nitrogen purity is decreased from 99.995% N_2 plus Ar to 98% N_2 plus Ar by decreasing the rectification capacity through removal of trays from the double column. The lower purity permits some additional withdrawal of nitrogen from the lower column and reduces the quantity of low pressure nitrogen which is sent to the nitrogen liquefier. The result is that a smaller N_2 makeup compressor is possible. The following table shows investment and power reductions which apply for 100% plant operating capacity (600,000 cfh (NTP) gaseous N_2 production capacity).

Incremental Investment and Power Reductions for Decreased N_2 Purity

Investment	- $14,000
Power	- 390 KW

This would amount to a unit cost decrease of 12¢ per ton of LIN based on a 5-year contract and a 0.6¢ per KWH power cost.

2. Increased Gaseous Nitrogen Production

Additional low purity N_2 gas is obtained by diverting some waste N_2 gas into the low pressure nitrogen product stream. This is accomplished without any cost or power premium. The maximum quantity of additional N_2 available is 1,840,000 cfh.

This gas is discharged from the cold box at about 15 psia. Investment and power requirements for compressing the maximum increment of 1,840,000 cfh into a distribution line at 100 psig are as follows:

Investment and Power Additions For Compressing Additional N_2 Gas	
Investment	$600,000
Power	4270 KW

The unit cost for this increment of increased production based on a 5-year contract period and a power cost of 0.6¢ per KWH would be 80¢ per ton.

3. Increased Oxygen Purity

An increase in oxygen product purity from 99.5% to 99.9% requires an increase in plant air plus some increase in discharge pressure of the air compressor. Total additional power required for making 800 TPD 99.9% O_2 will be 1300 KW. The investment premium will be around $400,000. This would amount to a unit cost increase of 85¢ per ton based on a 5-year contract period and 0.6¢ per KWH power cost. The problem of producing an even higher purity product becomes increasingly difficult and unit cost increases (above cost for producing 99.5% LOX) are roughly estimated as follows:

O_2 Purity	Unit Cost Increase
99.95	$5/ton
99.995	$12/ton

Some additional premium would be required for quality control, transportation and storage of the higher purity oxygen, however, this should not exceed $1 per ton for handling the large quantities considered here on a routine basis.

4. Decreased Parahydrogen Content

The hydrogen liquefier can be designed to produce product liquid hydrogen with continuous parahydrogen content variability between 97% and 25%. The hydrogen liquefier cold box becomes somewhat more complex to provide this flexibility, increasing its investment by about $50,000 for large plants (100 to 160 T/D). However, the production capability of a fixed facility increases substantially with decreased product parahydrogen content as indicated by Figure 39, appended.

For example, by building a 128 T/D 97% parahydrogen plant and investing \$50,000 extra in the cold box, the same plant can be adjusted to produce 160 T/D of 25% parahydrogen liquid (provided that the hydrogen production and purification train can process the increased product). This would have the effect of reducing overall hydrogen liquid production costs by approximately 7%.

2. Investigation of Co-Product Opportunities

a. Commercial Liquid Hydrogen, Oxygen and Nitrogen

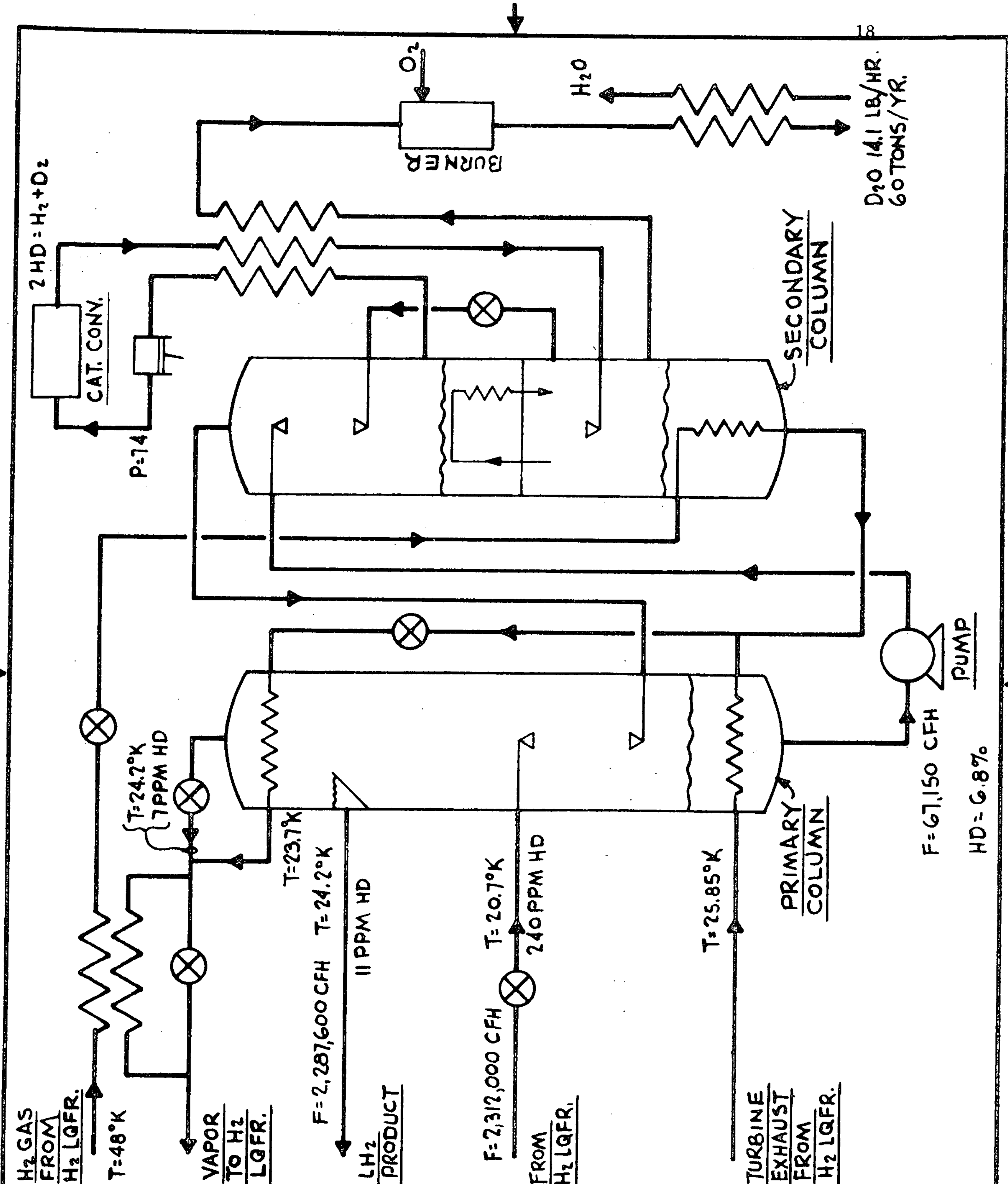
Plant cost data for the purpose of determining production costs for these commodities were aforementioned. The commercial market in the KSC area appears to have an attractive future growth potential. Food freezing and produce storage represent both current and future business opportunities of LIN. Areas such as electronics and metal reduction represent similar such opportunities for LH_2 and LOX as well as additional LIN.

b. Deuterium Recovery

Deuterium recovery has been considered from the point of view that in the event that the full production capability of the propellant production plant is not required, a deuterium recovery unit could be added in the future to help reduce the cost of producing propellants at the lowered production rates. Thus, the largest size deuterium unit which should be considered on this basis would be one capable of processing 140 TPD LH_2 for deuterium recovery. This arrangement completely utilizes the hydrogen recycle compressors which would be capable of making 160 TPD LH_2 if not operating in the deuterium recovery mode. Deuterium production when processing 140 TPD LH_2 would be around 60 tons per year. Investment in the deuterium recovery package, which consists mainly of distillation equipment operating at the temperature of liquid hydrogen as shown by Figure 40, is \$2,450,000 and 5,200 KW power is needed. The current world market price for deuterium is around \$20.50 per pound and the U.S. subsidized price is \$28 per pound. Figure 41, appended, presents unit costs for producing deuterium as deuterium oxide based on the above investment and power consumption figures for 5 and 15-year contract periods as a function of the deuterium plant utilization.

c. Methanol Production

Methanol production was also viewed as a means of using idled investment in the event total production from this propellant manufacturing facility is not needed. The basic process entails feeding a CO, H_2 synthesis gas mixture, which is withdrawn from the hydrogen generation portion of the LH_2 plant, to a methanol synthesis loop where they are catalytically converted to methanol (CH_3OH) as outlined by Figure 42. The process outlined in this figure is based on marginal equipment additions for making the methanol and utilizing as much of the LH_2 production equipment as possible.



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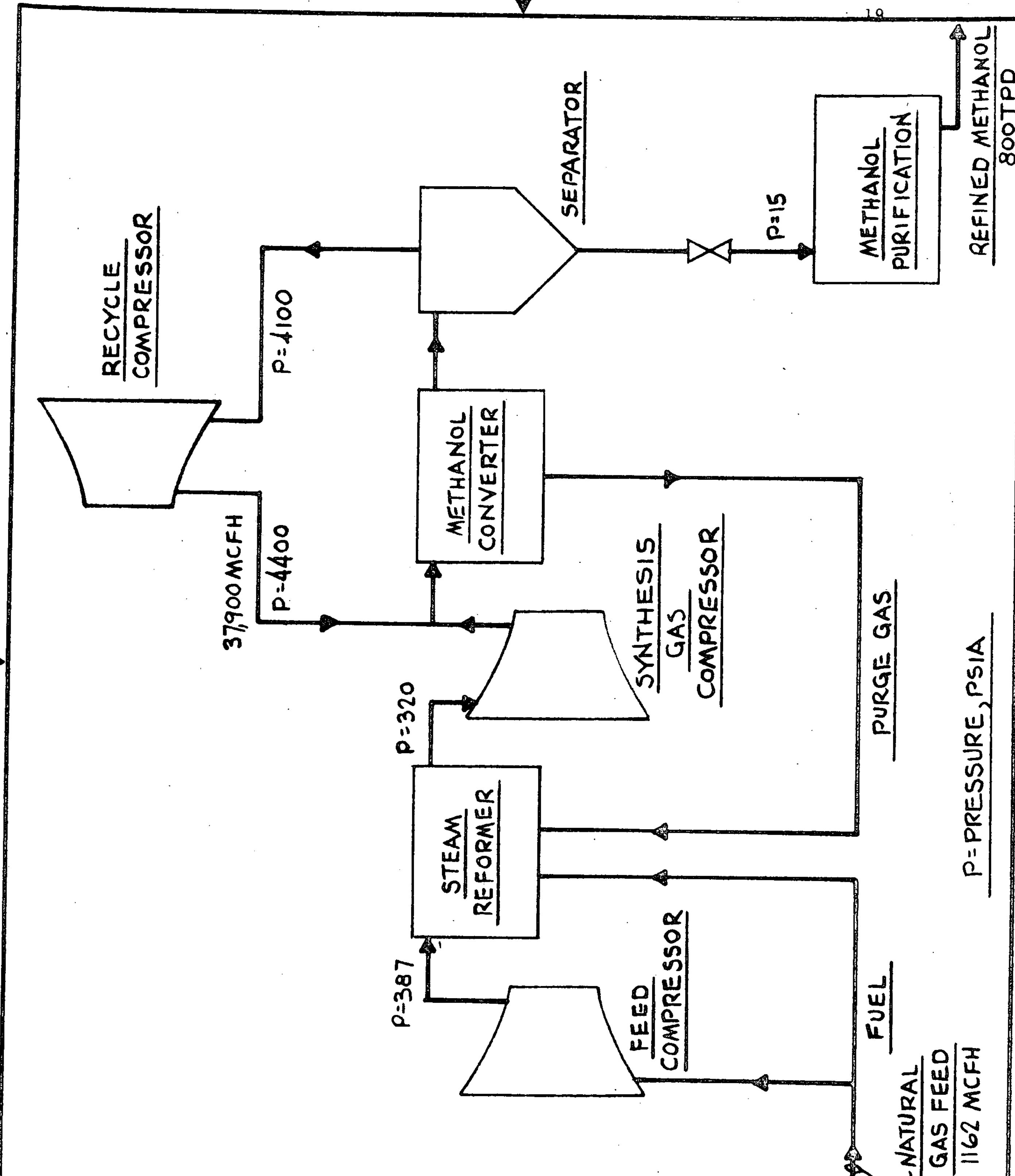
SYMBOL		PROJ. No. 7040	BY	DATE	CHK'D	LATEST ALT. LETT.
	DEUTERIUM RECOVERY PROCESS LIQUID HYDROGEN FEED	APPV'D	GROUP	SHEET	SHEETS	
		SCALE	FIGURE 40			



UNION CARBIDE CORPORATION
LINDE DIVISION
ENGINEERING DEPARTMENT • TONAWANDA, NEW YORK

SYMBOL	BLOCK FLOW DIAGRAM METHANOL PLANT	PROJ. No.	BY	DATE	CHK'D	LATEST ALT. LETT.
		APP'D	GROUP	SHEET	SHEETS	
		SCALE	FIGURE 42			

Investment and operating cost will be a function of the unutilized portion of the LH_2 plant. The lower the LH_2 product needs become, the greater will be the investment in the methanol plant because more synthesis gas is available from the LH_2 facility and the lower the unit methanol production costs due to economies of scale as indicated by Figure 43, appended. A 3-year payout period was used in determining the unit methanol costs which is typical for this business. Current methanol market prices range between 14¢ to 15¢ per gallon, F.O.B.

d. Ammonia Production

Ammonia is produced by catalytically combining nitrogen and hydrogen under high pressure and temperature conditions as shown by Figure 44. The hydrogen is purified cryogenically and delivered interstage to the synthesis gas compressor. Nitrogen gas is obtained from the air separation plant and delivered to the first stage suction of this compressor.

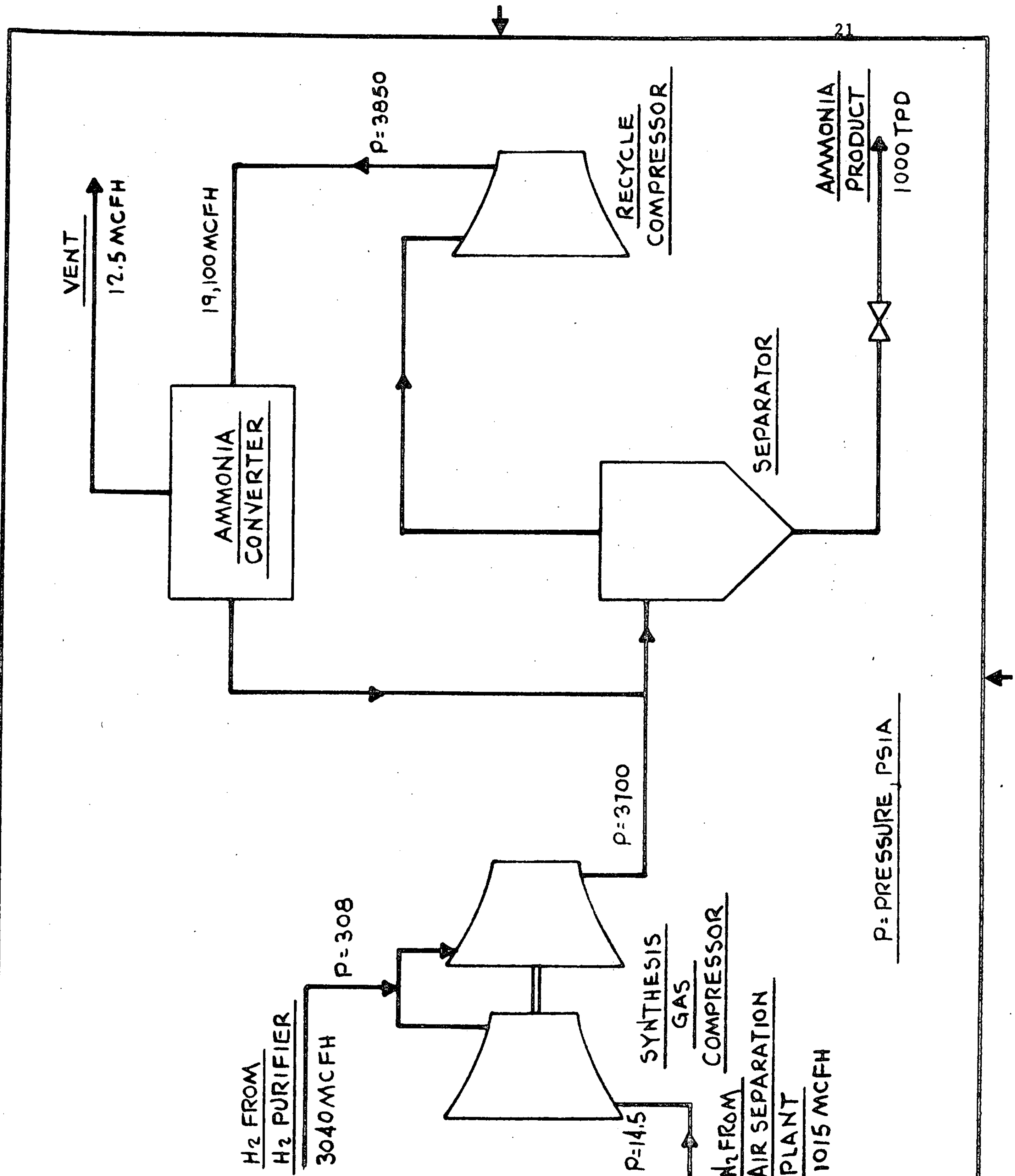
Because of the large size of commercial ammonia producing plants presently being installed, it was felt that ammonia production could only be attractive for a relatively large plant. Thus, investment and operating costs were determined for the extreme case wherein no LH_2 product would be required from the propellant production plant and its full product capability could be diverted to ammonia. Ammonia production in this mode of operation would be approximately 1,000 tons per day. Added investment in the synthesis loop and compression equipment would be $8,500,000 and 5,300 KW would be required. Modern 1,000 ton per day plants produce ammonia at about $20 per ton.

3. Energy Costs and Availability

a. Electric Power

The Florida Power and Light Company has adequate capability to supply the necessary electrical power to any location in the KSC area. The nearest plant generates 800,000 KW and total capacity of the system is 5,471,000 KW as of January, 1970. This compares with a maximum requirement of around 110,000 KW for the integrated propellant plant. In addition, the system has sufficient stiffness to permit starting the larger sized electrical motors being considered, including the 50,000 KW nitrogen recycle compressors.

FP & L's published rate for uninterrupted power is around 0.95¢ per KWH. However, for large power requirements in a case such as this where there are alternatives of using different fuels such as natural gas and fuel oil with other prime mover systems such as steam or gas turbines, this rate can be negotiated down considerably. It is estimated that 0.6¢/KWH uninterruptible power is probably achievable with a commitment to purchase 50,000 or more KW with a possibility of going as low as 0.5¢/KWH if commitment to 100,000 KW or more were made or if interruptible power were used.



UNION CARBIDE CORPORATION LINDE DIVISION ENGINEERING DEPARTMENT • TONAWANDA, NEW YORK	PROJ. No.	BY	DATE	CHK'D	LATEST ALT. LETT.
SYMBOL	BLOCK FLOW DIAGRAM AMMONIA PLANT	APPV'D	GROUP	SHEET	SHEETS	
		SCALE	FIGURE 44			

Future electricity prices will depend, to some extent, on the future price of fossil fuels for two reasons. First, the major portion of FP & L's power is generated from fossil fuel energy although the percentage generated from nuclear power is increasing. If fossil fuel costs increase we can expect to see some increase in electrical power. Such increases may be offset to some extent by technology gains in power generation cycles and equipment and economies of scale if the trend in building larger plants continues. The second reason for relating the future electricity price to fossil fuels is that, as mentioned above, in large power contracts such as this, a negotiated price below the published rate will be arrived at. The principal factor in determining this price will be the cost of alternatives for generating power.

b. Fuel Oil and Naptha

Fuel oil is tanked to the United States from both Venezuela and Africa. Availability is not a problem and should not be in the foreseeable future. Prices are subject to fluctuations, dependant on the domestic and world supply and political situation. For the quantities considered in this study, the price should fluctuate around 45¢ per million Btu's for low sulfur bearing fuel oil. Domestic produced fuel oil would be considerably more expensive.

Naptha would most likely be produced and refined in Venezuela for around 55¢ per million Btu's. One potential problem here is that a quota is presently required in order to purchase foreign naptha. Since the quota system applies mainly to naptha use for car fuels and domestic petrochemicals, it is highly probable that a permit to import can be obtained. The alternative of using domestic naptha would cost around 80¢ per million Btu's.

c. Pipeline Natural Gas

The Florida Gas Transmission Company's analysis indicates that natural gas in the quantities required for the large integrated propellant plant would not be made available at KSC if required today. Even supply for a 30 TPD LH_2 plant would probably not be possible at this time. The circumstance is not unique to the KSC area. A general supply problem involving natural gas exists throughout the United States. The problem of availability is due to the fact that gas prices are federally (Federal Power Commission) regulated. Current prices are sufficiently low that the incentive for exploration to find new reserves is not great.[1] There is much political pressure to raise prices which in turn will increase the incentive to find new reserves. If this happens, the supply situation for Florida and other areas will ease and there may be availability for a large hydrogen plant. One can only conclude that the situation is indefinite at present, however, if supply does improve the price will be greater than the current minimum which is around 40¢ per million Btu's on an interruptible basis. Fifty-cents per million Btu's was selected for the purpose of making comparisons.

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(1) R. E. Wright, "The Rise and Fall of Natural Gas Supply", presented at the 49th Natural Gas Processors Association (NGPA) Annual Convention, March 17 - 19, 1970, Denver.

d. Liquefied Natural Gas (LNG)

The LNG supply and cost picture, as it would pertain to this production facility, is quite uncertain at this time. This is because there are only a few LNG producing installations and most of the product from them is committed by long term contracts. The fuel requirements of this integrated propellant production facility are much smaller than those for which long term contracts have been committed thus far. For example, most contracts have been for around 200 MMSCFD LNG whereas the requirements for the propellant plant range between 30 and 60 MMSCFD dependent upon whether or not electrical power is used. This would indicate that an LNG venture to supply these requirements would have to combine several customers having similar requirements in order to be large enough to produce at attractive prices. This practice may start occurring if interest in LNG use continues to grow.

LNG prices as low as 50¢ per million Btu's have been reported. They, however, have been for large quantities with minimal shipping distances (Algiers to France). The most likely source of LNG for the KSC area would be Venezuela. Taking into account the cost of shipping this distance plus storage, it is estimated that around 80¢ per million Btu's would be the lowest achievable price for the required quantities of LNG.

4. Delivery and Storage Systems

a. Storage Tanks and Vacuum Insulated Piping

Liquid hydrogen tank cost, as a function of operating pressure, is given in Figure 45, appended. The largest tank considered by this graph was one-million gallons. Larger storage tanks, up to five-million gallons, were briefly investigated for low pressure (15 psig) service in an effort to capitalize on economies of scale. However, vendors' preliminary estimates for building such tanks were $1 per gallon which is the same as that for the million gallon capacity tank. This failure to realize any economy of scale is due to vendors' non-familiarity with the problems of building large tanks of this nature. Consequently, high engineering and labor premiums were estimated for the design and construction of the tanks to minimize possible risks. A funded study to examine this problem in more detail could lead to the development of sufficient know-how to permit constructing large LH_2 storage tanks at unit costs considerably lower than $1 per gallon. Figure 46, appended, presents the costs of low pressure liquid oxygen and liquid nitrogen storage.

Vacuum jacketed pipe 3" in diameter costs $150 per foot if installed above ground. In runs of 18-20,000 feet, losses are expected to be 5%.

b. Transport Equipment

Capital costs, capacities, and product losses for the various modes of transport are as follows:

1. Truck

Trucks with capacity for 3.9 tons of liquid hydrogen cost $145,000 each. Liquid oxygen and liquid nitrogen trucks have capacities of 20 tons and 16.8 tons, respectively, and cost $83,000. Although trailer evaporation is limited to 0.25% per day, losses from plant to use point are 8%. Operating costs were estimated to be $60 per round trip.

2. Rail

Rail cars with capacity for 11.8 tons of liquid hydrogen cost $250,000. Liquid oxygen and liquid nitrogen rail cars cost $120,000 each and have capacities of 90 tons and 64 tons, respectively. For normal service, liquid hydrogen can be moved for $225 per car, liquid oxygen for $90 per car, and liquid nitrogen for $64 per car. There is also an $11.5 switching charge that is added to each of the per car charges. Rail car losses are estimated at 7%.

3. Barges

A barge with a capacity of 72 tons of liquid hydrogen costs $900,000. Liquid oxygen and liquid nitrogen barges have capacities of 475 tons and 320 tons respectively, and cost $600,000 each. The Government owns three liquid hydrogen, three liquid nitrogen and three liquid oxygen barges of these capacities and they are currently in use at MTF. One 1200 HP tug is required per each barge. Dredging costs are estimated at 55¢ per cu. yard. Barge losses are 7% from plant to use point.

5. Site Investigation

Investigation of sites is divided into two principal categories, those being "on-site" or on government property near launch pad 39B from which the space shuttles will be launched and "off-site" or locations on private property which would be a greater distance away from the launching complex. Location near the launch pad would permit consideration of pipeline delivery of the propellants in addition to the more conventional means of rail, truck and barge. Off-site locations would be restricted to propellant delivery by means of rail, truck or barge because the greater distance from the launch pad would make the cost of pipeline prohibitive.

a. On-Site Locations

Two on-site locations were considered which are compatible with the following requirements:

1) Outside of 120 DB noise radius from Saturn launch areas. Personnel within the 120 DB areas require noise control during launches. Personnel within the 135 DB noise level (closer) must be evacuated during launches. Noise levels exceeding 135 DB also become damaging to buildings without special design.

2) Outside of .28 psi blast pressure area from launch explosions. Structures within this zone would require premium design for greater than the normal hurricane design forces of .28 psi.

3) Outside of blast fragment area from launch explosions, which would normally fall within the .4 psi zone.

4) Outside of crash clearance zone for all NASA and Air Force launch areas. Personnel within crash zones must be evacuated during launches.

5) Clear of present and planned operational areas.

6) Apparently clear of sight control lines which become more numerous closer to the launch areas.

The sites considered are referred to as NASA Site Number 1 and 2 as shown by Figure 47. Figure 48, appended, shows a detailed drawing for NASA Site #1 and Figure 49, appended, shows a detailed drawing for NASA Site #2. The #1 Site was selected because of its proximity to launch pad 39A while still fulfilling the constraining criteria listed above. If the propellant supply system for launch pad 39A and 39B were ultimately interconnected, this could be a favorable site location. Site #2 was selected because of its proximity to launch pad 39B while still being compatible with the above requirements. Both sites are characterized by sand dunes and swales formed by wave action when the sea level was relatively higher than it is today. Soil bearing is light, bearing loads of 2,500 to 4,000 pounds per sq. ft., and pilings would be required to support major equipment.

VIP pipeline costs to connect the two sites to the launch pads can be determined by using the footage costs reported previously. Cost discrepancies which would result in differences between plant investment costs, which were reported on a general basis earlier in this report, and these specific sites are listed in the following table:

NASA Site #1

Item	Cost Adjustment
1. No land cost	-$500,000
2. Rail siding or double handling of large equipment	+$200,000
3. Additional cooling water piping	+$600,000
Net Premium	+$300,000

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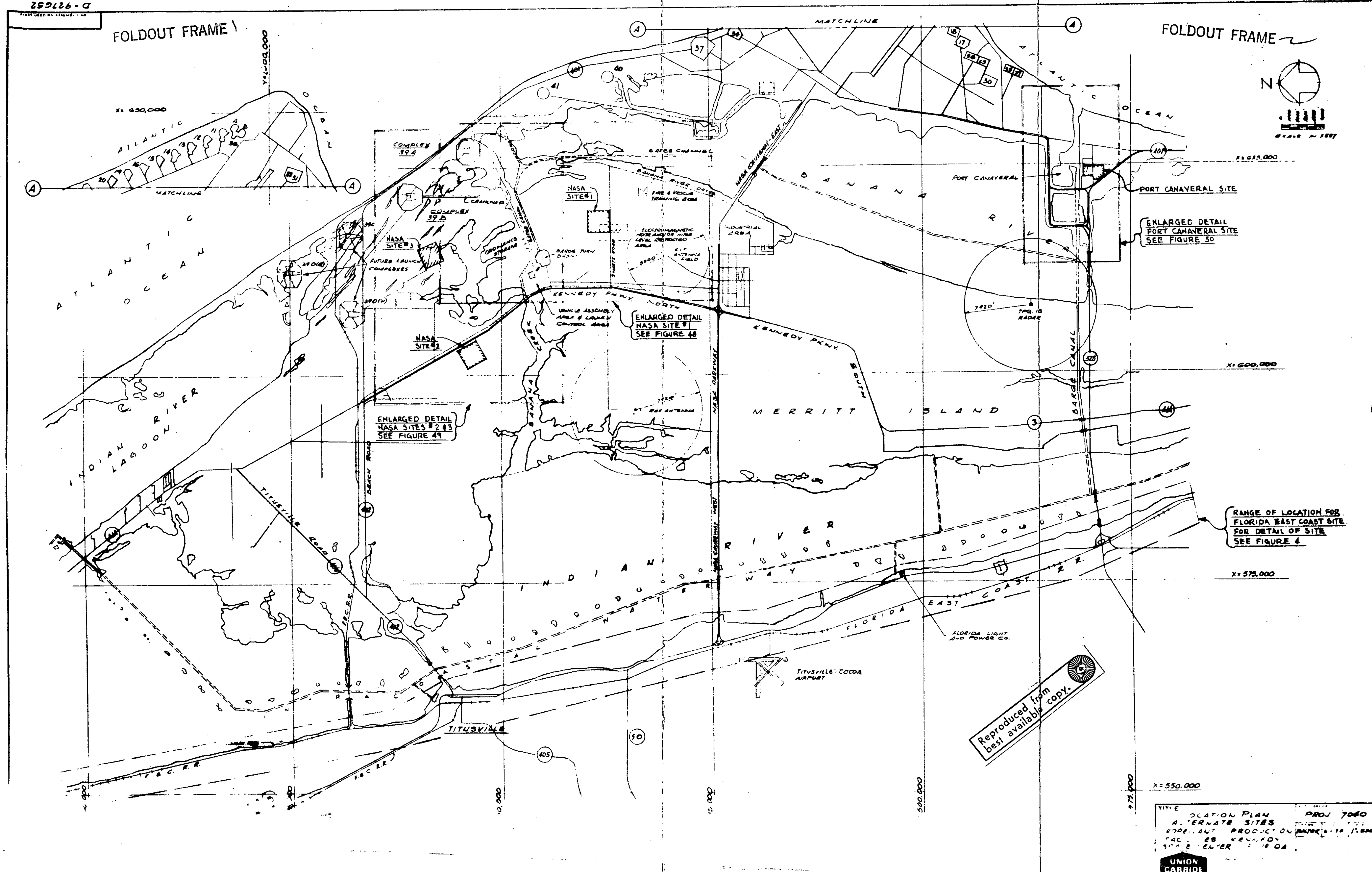
FOLDOUT FRAME 1

FOLDOUT FRAME 2



NASA Site #2

Item	Cost Adjustment
1. No land cost	-\$500,000
2. Additional cooling water piping	+\$400,000
Net Reduction	-\$100,000

Another possibility with regard to the on-site locations is to locate the production plant closer to the launch pads. This, of course, would subject the plants to greater potential blast overpressures, noise levels, and ground transmitted vibration frequencies during a launch. Process equipment would have to be protected from and/or designed to withstand the greater vibration frequencies and overpressures and personnel would have to be protected from both the overpressures and greater noise levels. Personnel protection could be accomplished by locating the control room outside the restricted area and equipment can be protected by proper design precautions. Liability in the event a launched vehicle were to abort and crash and consequently damage the production facility would remain a final obstacle with this alternative.

The point specifically considered as NASA Site #3 was one approximately 5,600 ft. from launch pad 39B on a line connecting NASA Site #2, discussed above, with this launch pad as shown by Figure 47 and in detail by Figure 49, appended. This distance from the launch pad would experience a 0.8 psi overpressure from the explosion of a fully fueled Saturn vehicle and a 137 decible (range from 133 to 141 DB) noise level. The 0.8 psi overpressure from an explosion would be an instantaneous pressure which would be equivalent to the 0.28 steady state overpressure which is used for design against normal hurricane forces. Thus, the design cost premiums that would have to be added to a plant located this close to the launch pad would be those due to noise level considerations and ground transmitted vibration frequencies. Some of these considerations would be as follows:

1) All control instruments would have to be located inside a building specially designed to withstand and attentuate the high noise level.

2) Either locate the control room remotely (3 to 4 miles away) running a conduit containing electrical signals from the plant to the control room and evacuate all maintenance and service personnel during launching periods or design a special control building at the site which would contain all personnel during the launch operation and attentuate the noise. Costs premiums for these two alternates are considered approximately equal.

3) Bypass air intake of air compressor for the air separation plant to prevent surging.

4) Brace small pipes, lines and tubing on smaller spans.

5) Check designs to insure there are no potential noise resonance or machine-ground vibration resonance problems.

6) Check support of power transmission cables.

7) Use of heavier, more expensive machine and major equipment foundations.

A very rough estimate of the investment premium in terms of added engineering and equipment costs to resolve the above considerations plus others which may become apparent after a more detailed engineering study would be 1.25 to 1.75 million dollars for the integrated propellant production plant. Other cost adjustments which should be made to place the costs of building a plant on this site on a consistent basis with a general plant site are as follows:

NASA Site #3

	Item	Cost Adjustment
1.	No land cost	- $500,000
2.	Addition of roadway	+ $150,000
3.	Additional cooling water piping	+ $400,000
4.	Rail siding or double handling of large equipment	+ $200,000
5.	Facility Hardening	+$1,500,000
	Net Premium	+$1,750,000

b. Off-Site Locations

Two off-site locations have been investigated, those being one at Port Canaveral and the other being a general site on the Florida East Coast, near the Florida East Coast Railroad line and within a one hour one-way truck driving distance from the shuttle launch complex. The Port Canaveral Site is also indicated by Figure 47 and is shown in detail in Figure 50, appended. This site was primarily considered because it is ideally suited for barging operations. In the event foreign naptha or fuel oil is used, this would be hauled into the Port by ocean tankers and emptied into storage tanks located there. All other sites being considered would require either pipelining or barging this fuel from the Port location. The nearby Florida Power and Light Company plant uses a barging operation to supply its required fuel oil. This double handling could be avoided by locating the production plant at the Port. There are no railroad tracks near this location and thus the only alternatives available for transporting propellants to the launch complex are barging and trucking. Cost adjustments to the "general site" costs which were presented previously are as follows:

Port Canaveral Site

1.	No land filling required	-\$400,000
2.	Double handling of all large equipment during construction	\$200,000
3.	Additional cooling water return piping	\$800,000
	Net Premium	+\$600,000

The general Florida East Coast area was considered because there are many good locations available for siting a plant and product can conveniently be transported by all three conventional means - rail, truck, and barge. Location near the Florida Power and Light plant was specifically investigated with the intent of obtaining a bus-bar power rate by eliminating lines for power transmission. This did not prove attractive because of the necessity of tying other plants into the power supply grid for the purpose of backup in the event a given power plant should go out of operation. No adjustment in costs are required to place a reasonably well selected site in this general area on a consistent basis with the general costs presented earlier. Dredging would be required to connect a site to the Intercoastal Waterway in the event barges are used and this is estimated to cost around \$200,000.

Florida East Coast Site

Dredging for barge channel	+\$200,000 (Net Premium)

B. Economic Analysis

Having developed the basic cost and performance data for the various factors concerned with the production and delivery of propellants, the objective now is to choose the best system from the many possible alternatives. This section will be concerned with determining those conditions for deciding (a) Whether or not the production facility should be integrated, (b) Whether steam reforming or partial oxidation is favored for generating hydrogen, (c) Whether to use electric motors, steam turbines, or gas turbines to drive compression equipment, (d) When pipeline natural gas, liquefied natural gas, naptha or fuel oil should be used, (e) What redundancy or backup provisions shall be made, (f) What value can be realized for co-products manufacture, (g) Whether products should be delivered by truck, rail, barge, pipeline, or combinations thereof and, (h) Whether the site should be located on government property or not. Changes in the cost of some of the input factors between now (1970) and the time a plant would be installed and started (1977 or 1978 at the earliest) may lead to altering conclusions based on both present day actual and projected costs. Therefore, cost impact of factor input cost changes will also be presented to permit rapid reevaluation at any point in time.

Costs have been determined on the basis that the production and distribution facilities will be industry financed. Contract lengths of 5, 10 and 15 years were considered to determine the impact on both unit cost and conclusions concerning selection of the optimum system. Insurance and provision for casualty losses on capital investment were assumed to be 1-1/2% of the capital investment. Return on investment was assumed to be 10% per year. This rate includes the profit, interest, and provision for income taxes. It should be cautioned that during periods of tight money this rate would be higher and therefore the hydrogen costs estimated for 1970 would be somewhat low. The working capital (inventory, spare parts, and cash) which is required to operate a production facility was assumed to be 15% of the capital investment. A return of 10% was also charged on this amount (i.e. working capital cost equals 1.5% of the capital investment). These total charges which were added to the operating costs, therefore, amounted to 33% of the initial plant cost per year for a 5-year contract, 23% per year for a 10-year contract and 19.7% per year for a 15-year contract. All capital and operating costs are presented on the basis of 1970 dollars.

1. Propellant Manufacturing Plant

Cost comparisons made here will be based on the best current estimates of electric power and fuel energy costs. These previously stated costs are 0.6¢ per KWH for electric energy, 45¢ per million Btu's for fuel oil, 50¢ per million Btu's for pipeline natural gas, 55¢ per million Btu's for foreign naptha, 80¢ per million Btu's for domestic naptha and also 80¢

per million Btu's for LNG. Though natural gas is not presently available for use, costs are presented for the purpose of comparison and possible applicability in the future in the event that the current natural gas shortage problem is resolved.

All comparisons in this section are made on a unit cost (dollars per ton for the liquid air products and cents per pound for liquid hydrogen) rather than "total-cost-of-program" basis to better compare smaller plants with larger plants and show the affect of plant utilization. This does pose a problem for the integrated plant cases and that is that costs must be allocated between the different products. This was resolved by assigning full, non-integrated costs to the liquid oxygen and nitrogen products and subtracting these costs from the total integrated plant costs. The residual cost is then assigned to the liquid hydrogen product, thus all production cost advantages associated with integration can be observed by comparing the integrated and non-integrated LH_2 costs.

a. Air Separation and Liquefaction

Costs for producing LOX and LIN separately are presented by Figure 51 for 5, 10 and 15-year contract periods. Two different capacity plants are considered for each product, along with resultant costs if the full production capacity of the plant is not utilized. For LOX, costs for maximum plant production capacities of 800 TPD and 200 TPD are presented and for LIN, costs for 400 TPD and 100 TPD capacity plants are shown. LIN costs are based on the presumption that a gaseous nitrogen supply is available as a by-product from an air separation plant at no cost. All cases shown are based on use of electric motor drive as this arrangement proved most attractive in all instances.

Costs for producing liquid oxygen and nitrogen from a facility capable of producing 800 TPD LOX and 400 TPD LIN based on a 5-year contract or evaluation period are presented by Figure 52 as a function of production capacity. One of the major assumptions on which this graph is based is that the corresponding LIN quantities are one-half the LOX quantities in all instances. This presumption of a 2:1 LOX to LIN ratio is an important one because the unit cost for producing the 400 TPD LIN could not be achieved unless the 800 TPD LOX were produced simultaneously. This can be observed by comparing the costs presented by Figure 52 for the combined production case with those presented for the separate production cases by Figure 51. One final observation here is that the LOX costs are considerably higher than the LIN costs because all air separation costs were assigned to the LOX.

Comparing the three prime mover systems considered for driving the compression equipment, electric motors, steam turbines and gas turbines, the electric motor drive case is the most attractive based on the energy costs assumed. This is because the rather short 5-year evaluation period strongly favors the process requiring the least investment which is the electric motor case. At low utilization, the lowest investment case becomes even more relatively attractive. Changes in the cost of utilities could alter this conclusion and the impact of such changes can be determined by the following table:

Figure 51

UNIT AIR SEPARATION & LIQUEFACTION COSTS

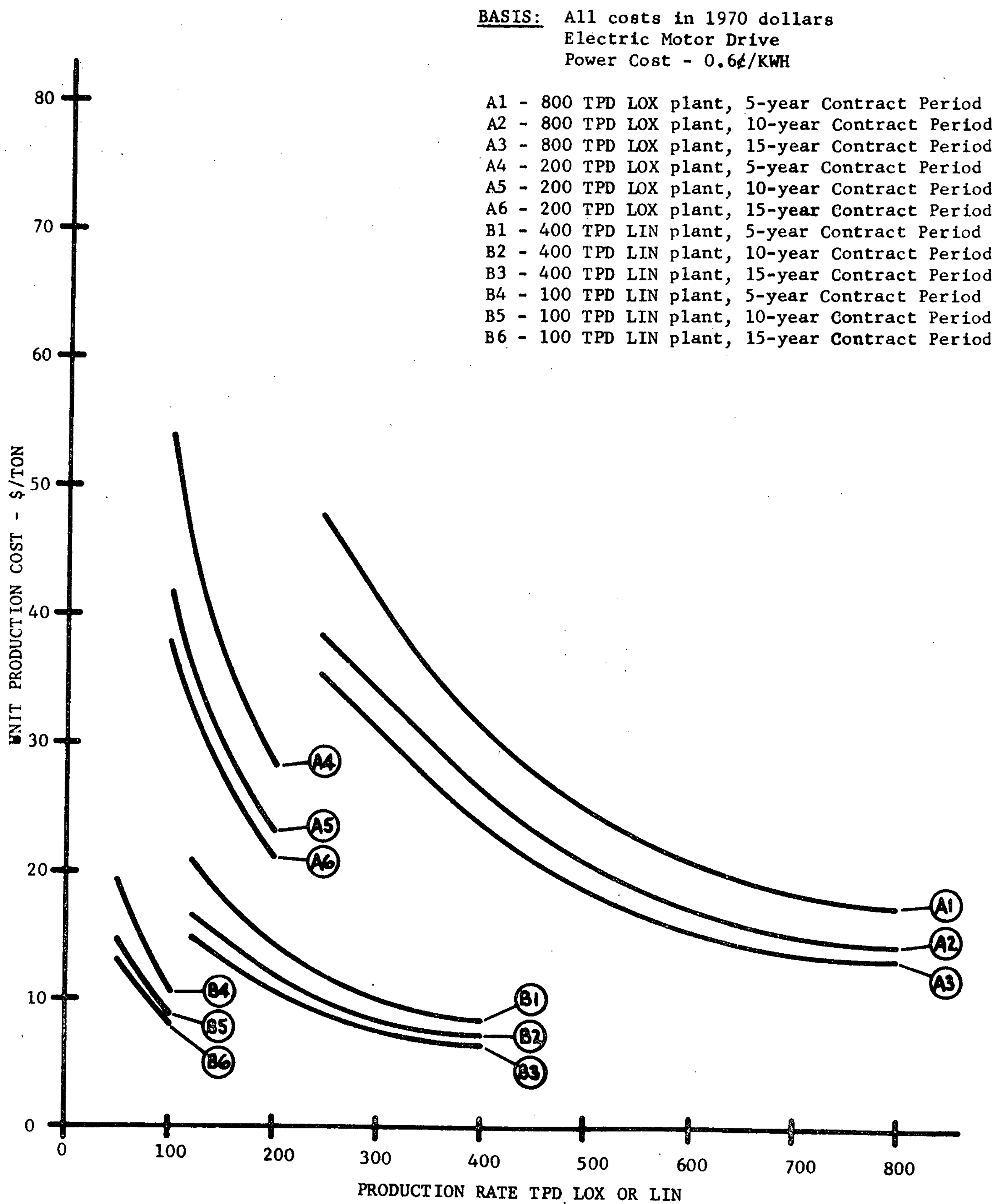


Figure 52

UNIT AIR SEPARATION & LIQUEFACTION COSTS FROM A PLANT WITH A MAXIMUM PRODUCTION CAPABILITY OF 800 TPD LOX - 400 TPD LIN

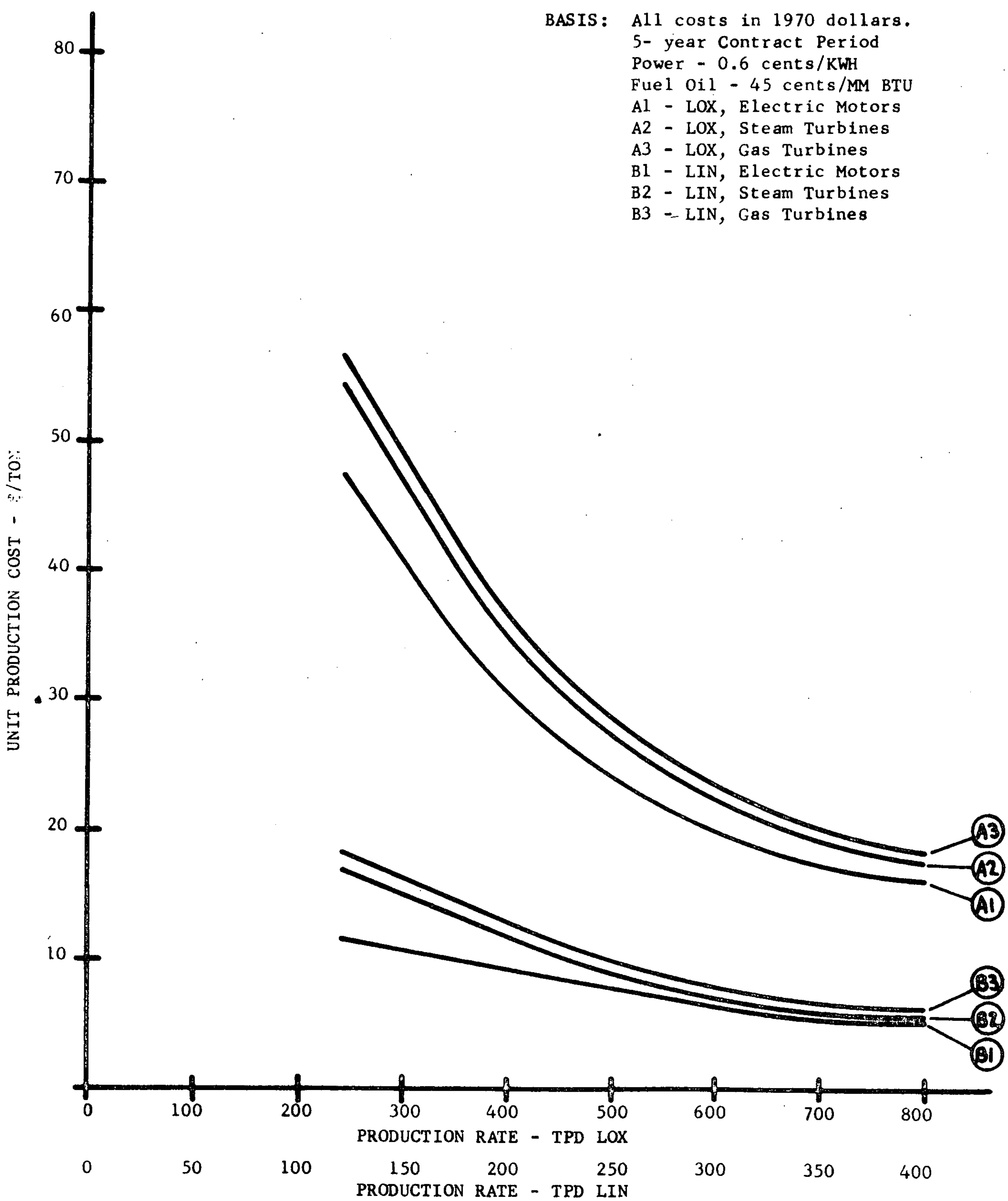


Figure 53

UNIT AIR SEPARATION & LIQUEFACTION COSTS FROM A PLANT WITH A MAXIMUM PRODUCTION CAPABILITY OF 800 TPD LOX-400 TPD LIN

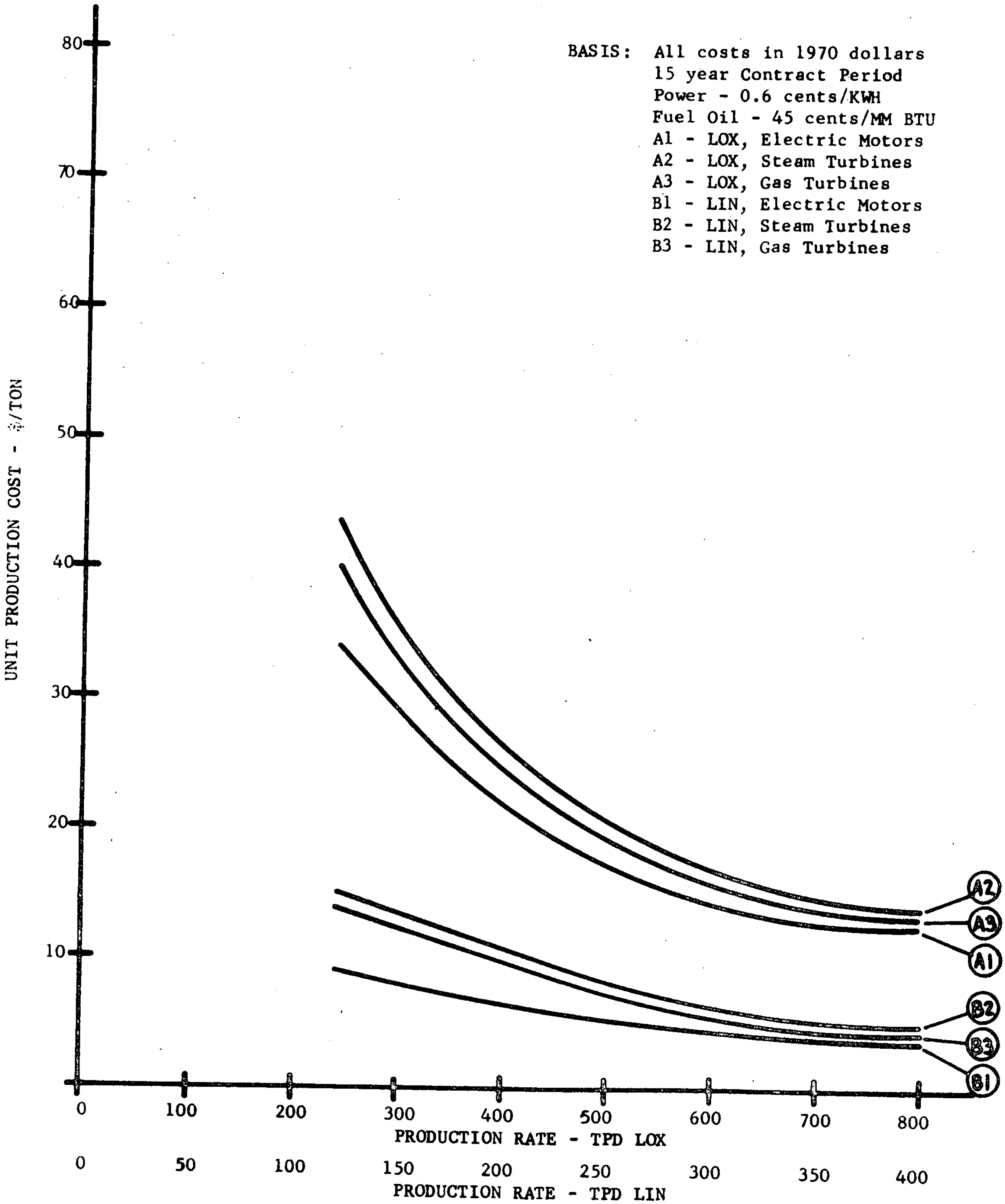
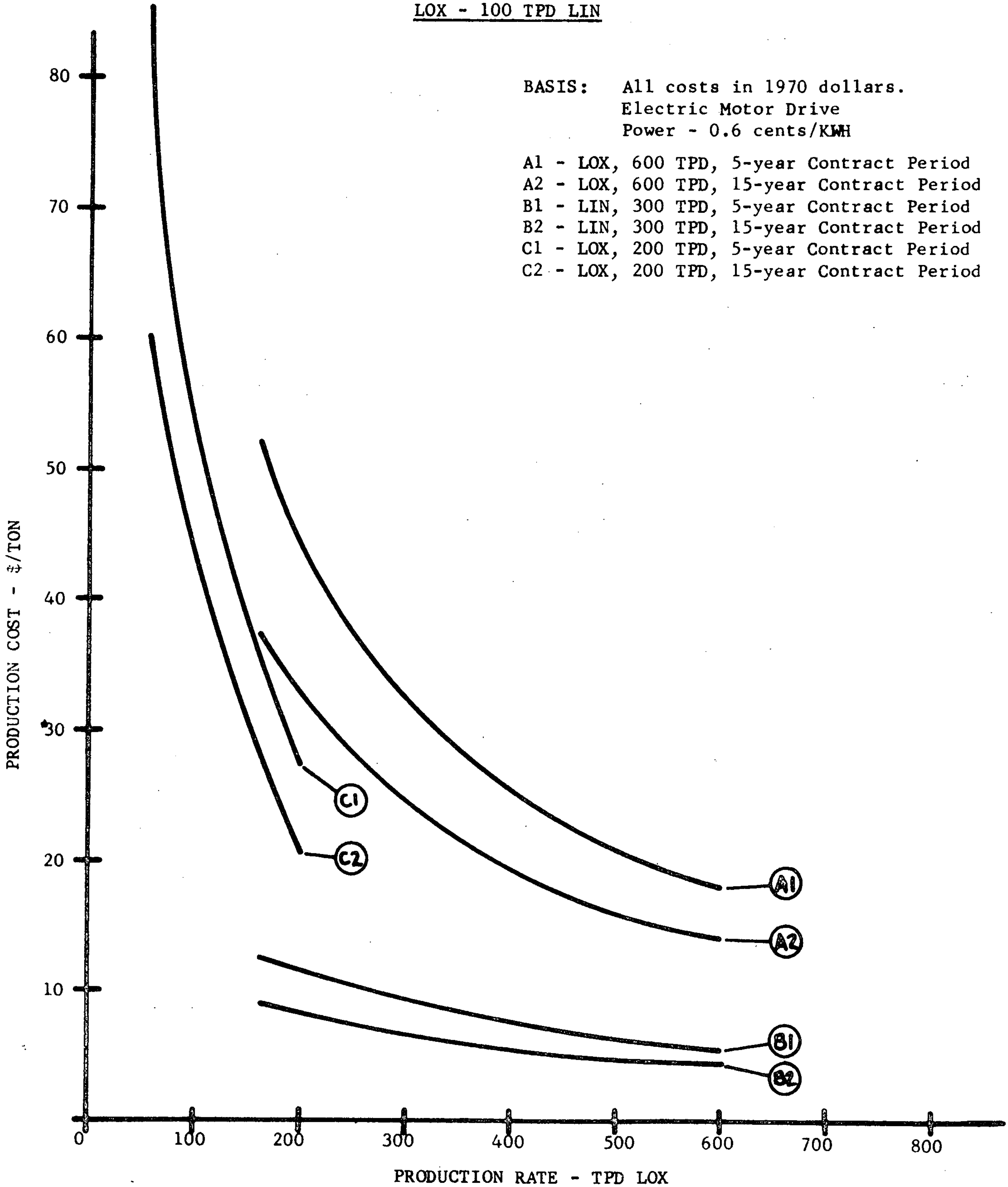


Figure 54

UNIT AIR SEPARATION & LIQUEFACTION COSTS FOR PLANTS HAVING MAXIMUM PRODUCTION CAPABILITIES OF 600 TPD LOX-300 TPD LIN & 200 TPD LOX - 100 TPD LIN



Utility	Prime Mover	Price Change	Change in Unit Production Cost - $/Ton LOX	LIN
Electricity	Motors	0.1¢KWH	0.82	0.45
Fuel Oil	Steam Turbines	10¢/million Btu's	0.73	0.40
Fuel Oil	Gas Turbines	10¢/million Btu's	0.59	0.32

Figure 53 presents the same comparison for a 15-year evaluation period as was presented by Figure 52 for a 5-year evaluation period. Here again, the electric motor drive case is more attractive than the steam and gas turbine drive cases although the relative difference is not quite as great due to the longer evaluation period moderating the investment cost differential.

Comparisons of non-integrated air separation and liquefaction plants designed for lower production rates are presented by Figure 54 for 5 and 15 year evaluation periods. Only the electric motor driven cases are presented here because at the lowered design production rates, the lowest investment cases will always prove relatively more attractive than at the higher production levels. The principal observations to be made in examining Figures 51-54 are that costs are significantly influenced by the length of evaluation period, size of plant and the production level of a given plant design.

b. Liquid Hydrogen Production - Integrated Plant

Having established the unit production costs for LOX and LIN, the integrated plant LH_2 production costs can now be determined by subtracting these costs from the total integrated plant costs as outlined above. Since the electric motor drive cases were lowest cost for producing LOX and LIN throughout, these will be used as the basis in all cases.

Production costs are presented as a function of capacity for the most attractive combinations of prime movers and hydrogen generation units for 5, 10 and 15-year evaluation periods by Figures 55, 56, and 57, respectively. Maximum design capacity of the plant is 160 TPD LH_2, 800 TPD LOX and 400 TPD LN_2 in all cases. Production at reduced levels though represented in terms of LH_2 production, represents total propellant production in the ratio of 1 TPD LH_2:5 TPD LOX:2.5 TPD LN_2. Examining these illustrations in more detail, Figure 55 indicates the pipeline natural gas case using electric motors as prime movers to be the lowest cost case. Unfortunately, this case is unrealistic because as stated previously, pipeline natural gas is not currently available in required quantities. Examining those cases which can be realistically considered, it can be observed that in the high production capacity end, costs are nearly a toss-up for the three prime mover systems being considered for the steam reforming process using naptha feed. At the lower production capacity end, the lower investment electric motor drive case becomes

Figure 55

LH$_2$ PRODUCTION COSTS FOR AN INTEGRATED PROPELLANT PRODUCTION PLANT WITH MAXIMUM PRODUCTION CAPABILITY OF 160 TPD LH$_2$, 800 TPD LOX, 400 TPD LIN

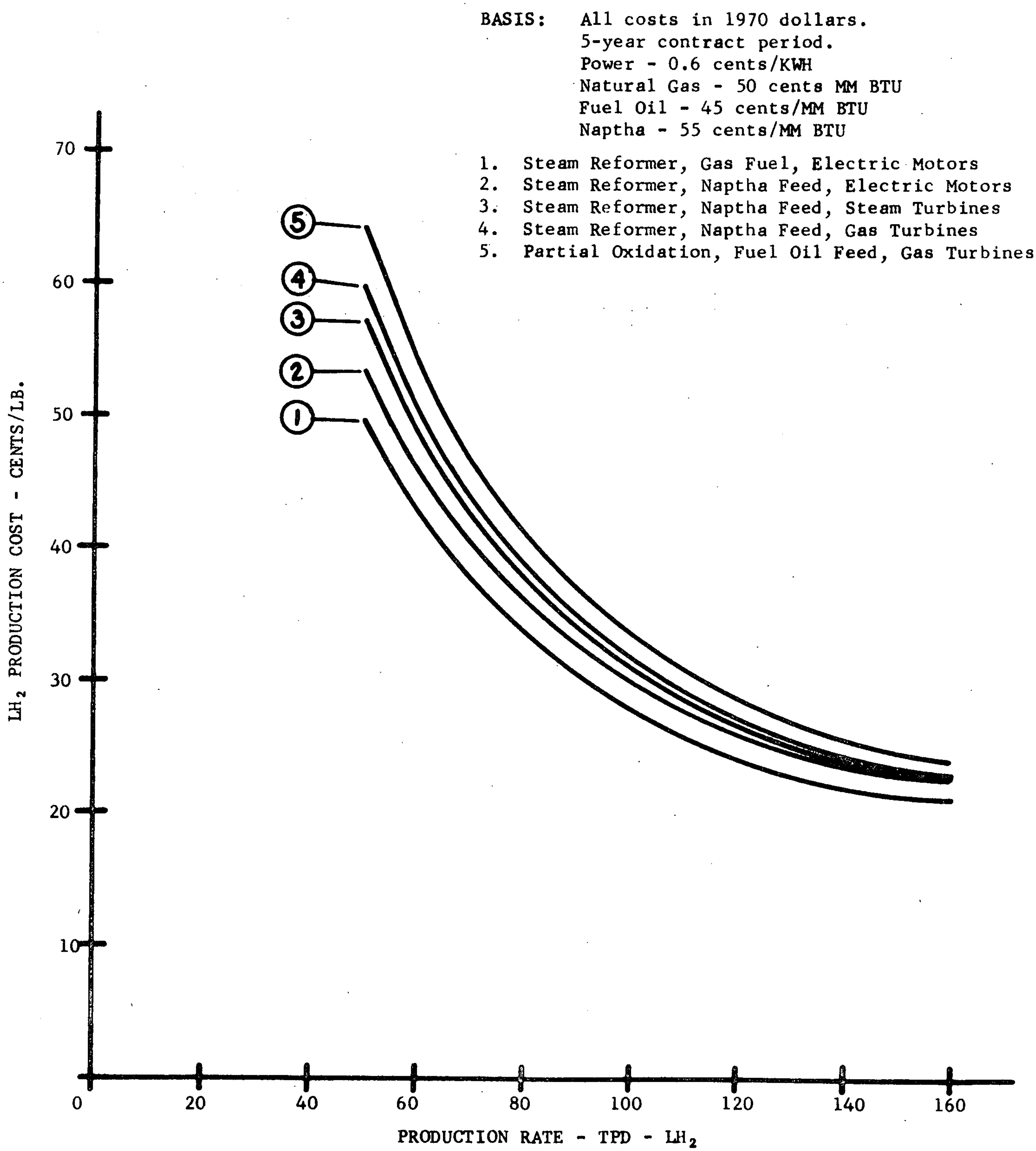


Figure 56

LH_2 PRODUCTION COSTS FOR AN INTEGRATED PROPELLANT PRODUCTION PLANT

WITH MAXIMUM PRODUCTION CAPABILITY OF 160 TPD LH_2, 800 TPD LO_2, 400 TPD LIN

BASIS: All costs in 1970 dollars
10-year Evaluation Period

Power - 0.6¢/KWH
Natural Gas - 50¢/MM Btu
Fuel Oil - 45¢/MM Btu
Naptha - 55¢/MM Btu

1. Steam Reformer, Gas Fuel, Electric Motors
2. Steam Reformer, Naptha Feed, Electric Motors
3. Steam Reformer, Naptha Feed, Gas Turbines
4. Partial Oxidation, Fuel Oil Feed, Gas Turbines

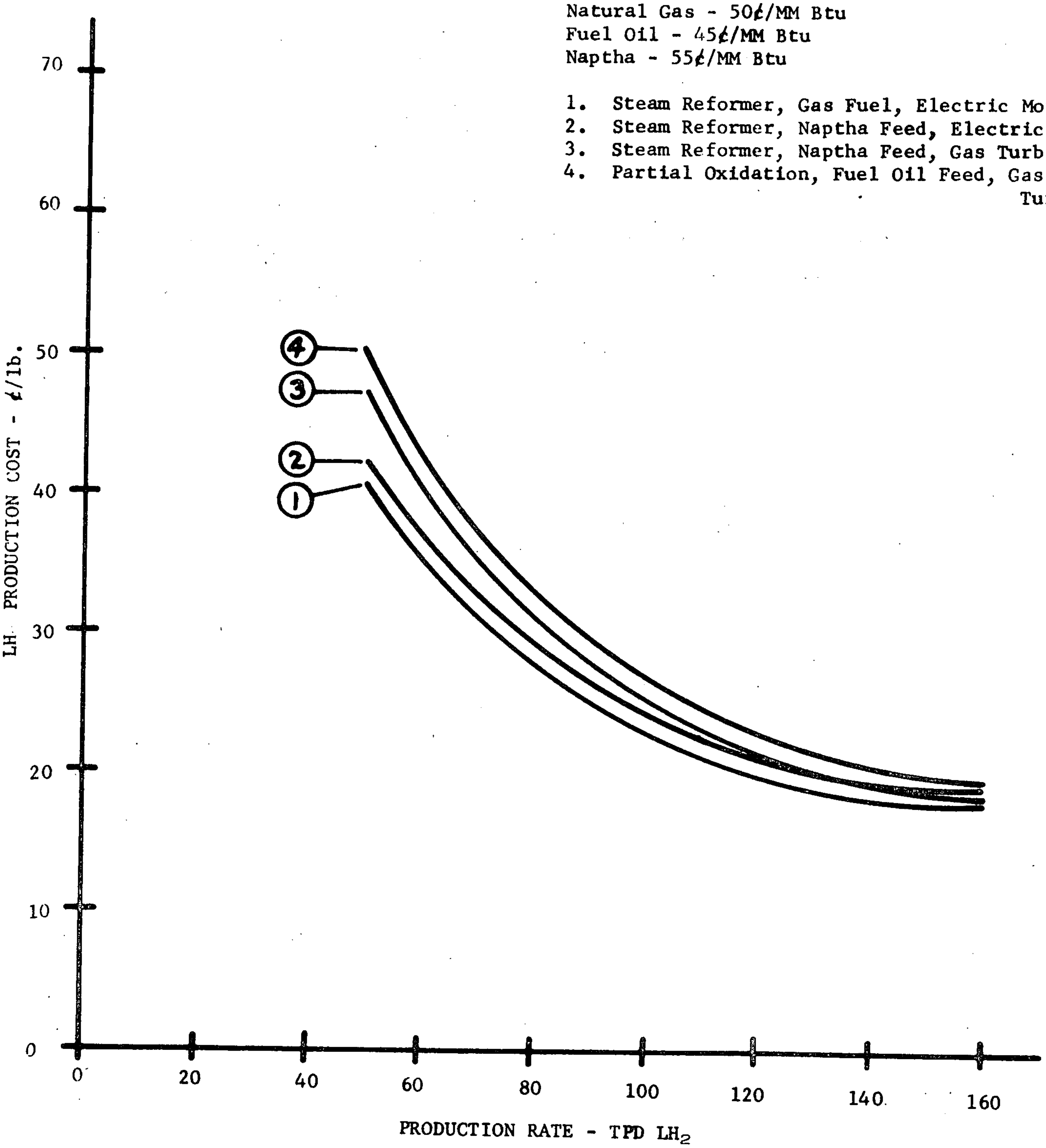
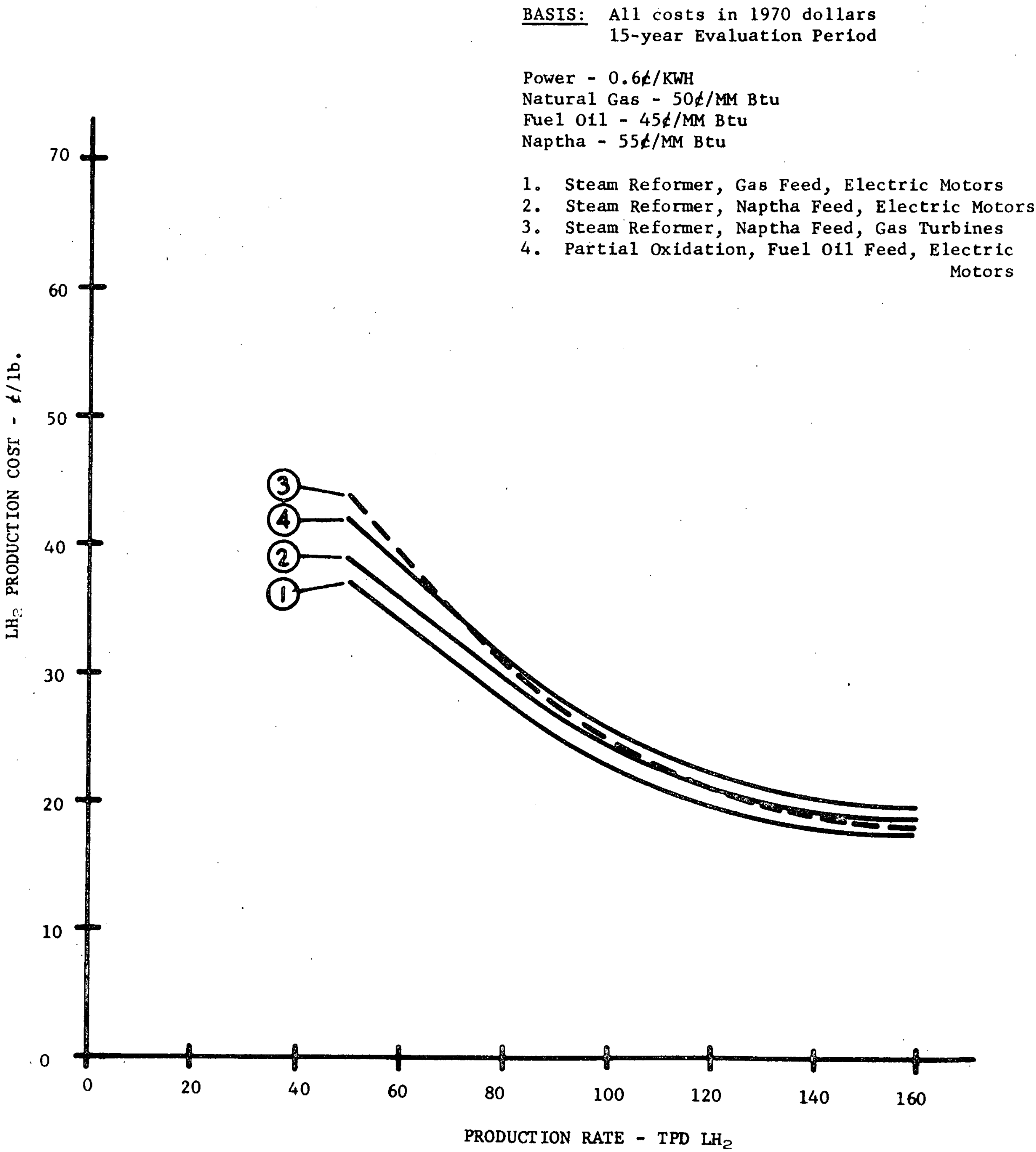


Figure 57

LH$_2$ PRODUCTION COSTS FOR AN INTEGRATED PROPELLANT PRODUCTION PLANT WITH MAXIMUM PRODUCTION CAPABILITY OF 160 TPD LH$_2$, 800 TPD LO$_2$, 400 TPD LIN



relatively more attractive. In all cases, the partial oxidation process, with its higher investment cost, proved less attractive. One case based on using fuel oil feed and gas turbine drive is presented for the purpose of comparison. This case had the lowest production cost of all partial oxidation processes considered in the high production rate range (130 to 160 TPD).

Figure 56, differing from 55 in length of evaluation period (10 years vs. 5), again shows the pipeline natural gas case to be potentially most attractive based on the utility costs assumed. Considering the cases which should be considered more realistic, the gas turbine drive case proves more attractive than the electric motor drive case for the naptha feed steam reformer in the high production capacity ranges. This is because the lower operating costs of the gas turbine drive system more than offset the investment premium over electric motors when the evaluation period becomes long enough. At the low production end, the electric motor drive case, with its lower investment, starts appearing more attractive. The steam turbine drive case was not presented here because in all instances it proved less attractive than either the electric motor and/or the gas turbine drive cases. Again, the lowest cost partial oxidation case in the high production level range, which is based on use of fuel oil feed and gas turbine drive, is presented as a basis for comparison.

Examination of Figure 57, which presents cost data based on a 15-year evaluation period, results in drawing conclusions similar to those drawn for Figure 56, above. Minor differences are that the unit costs for producing hydrogen are lowered and the naptha fueled stream reformer case using the higher investment, lower operating cost gas turbine drive looks relatively better than the electric motor drive case in the high production range. This is again because the longer evaluation period moderates the impact of the investment premium.

Production costs for a 120 TPD integrated propellant production plant for various combinations of prime movers, hydrogen generation units and fuels are presented by Figures 58 and 59 for 5 and 15-year evaluation periods, respectively. The 10-year evaluation period presentation was not provided because it showed the same relative comparisons as the 15-year period case. The 120 TPD case was selected because it is representative of production requirements to support 104 shuttle lanuches per year if transportation losses are minimized. Figure 58 shows the electric motor drive cases to be better than gas turbine drive. This is somewhat different from the 160 TPD case for a 5-year evaluation period in which all the prime mover systems showed similar costs in the high production range. The reason for this change is that for the smaller sized plants initial investment has a greater influence on costs, particularly for a short evaluation period. Thus, the lower investment cost, higher operating cost electric motor drive case appears more attractive at all production levels for the naptha feed steam reformer case. Steam turbine drive cases, while not plotted are extremely

Figure 58

LH$_2$ PRODUCTION COSTS FOR AN INTEGRATED PROPELLANT PRODUCTION PLANT WITH MAXIMUM PRODUCTION CAPABILITY OF 120 TPD LH$_2$, 600 TPD LOX, 300 TPD LIN

BASIS: All costs in 1970 dollars
5-year Contract Period

Power - 0.6¢/KWH
Natural Gas - 50¢/MM Btu
Fuel Oil - 45¢/MM Btu
Naptha - 55¢/MM Btu

1. Steam Reformer, Gas Fuel, Electric Motors
2. Steam Reformer, Naptha Fuel, Electric Motors
3. Steam Reformer, Naptha Fuel, Gas Turbines
4. Partial Oxidation, Fuel Oil, Electric Motors

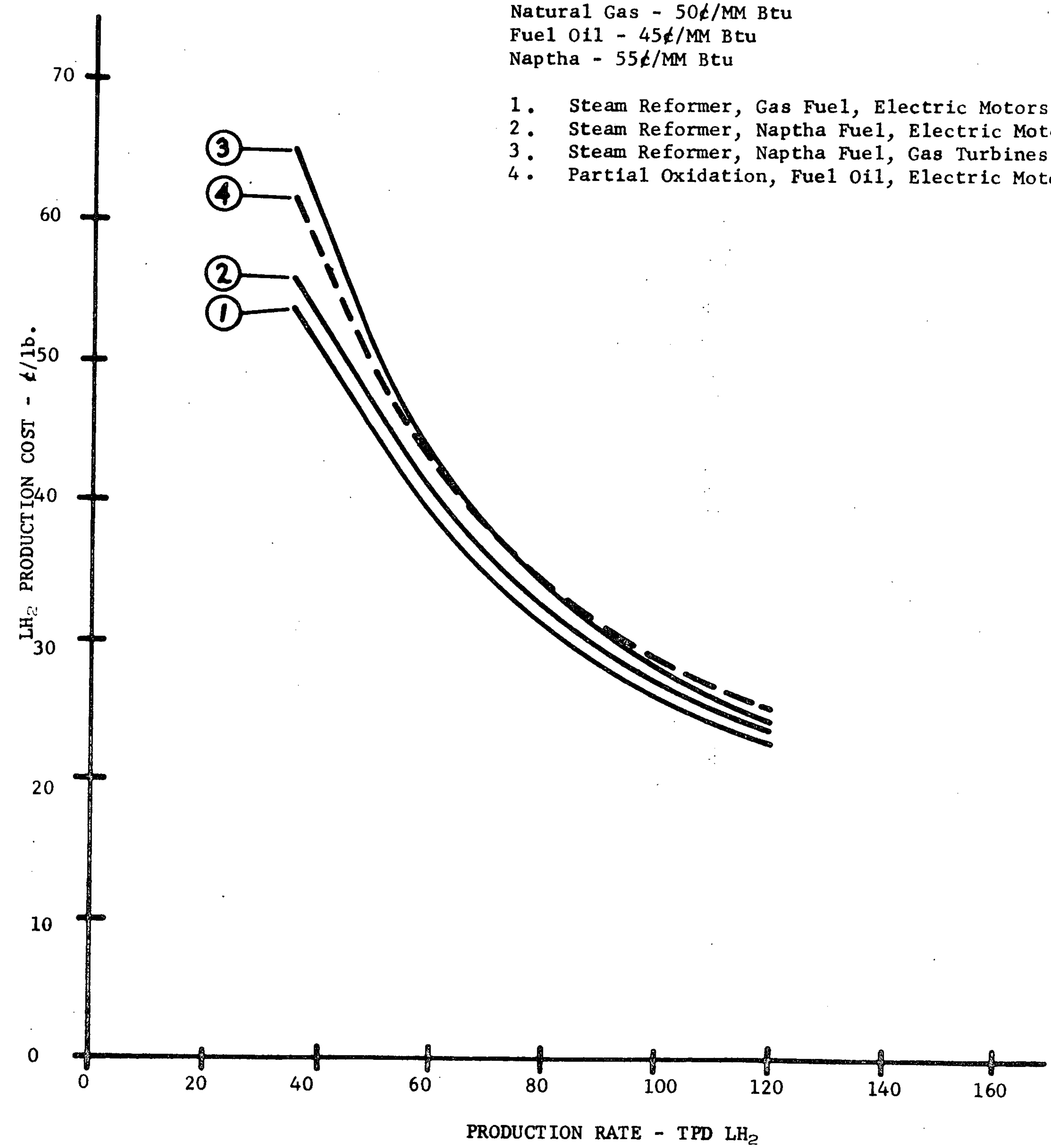


Figure 59

LH$_2$ PRODUCTION COSTS FOR AN INTEGRATED PROPELLANT PRODUCTION PLANT WITH MAXIMUM PRODUCTION CAPABILITY OF 120 TPD LH$_2$, 600 TPD LOX, 300 TPD LIN

BASIS: All costs in 1970 dollars
15-year Evaluation Period

Power - 0.6¢/KWH
Natural Gas - 50¢/MM Btu
Fuel Oil - 45¢/MM Btu
Naptha - 55¢/MM Btu

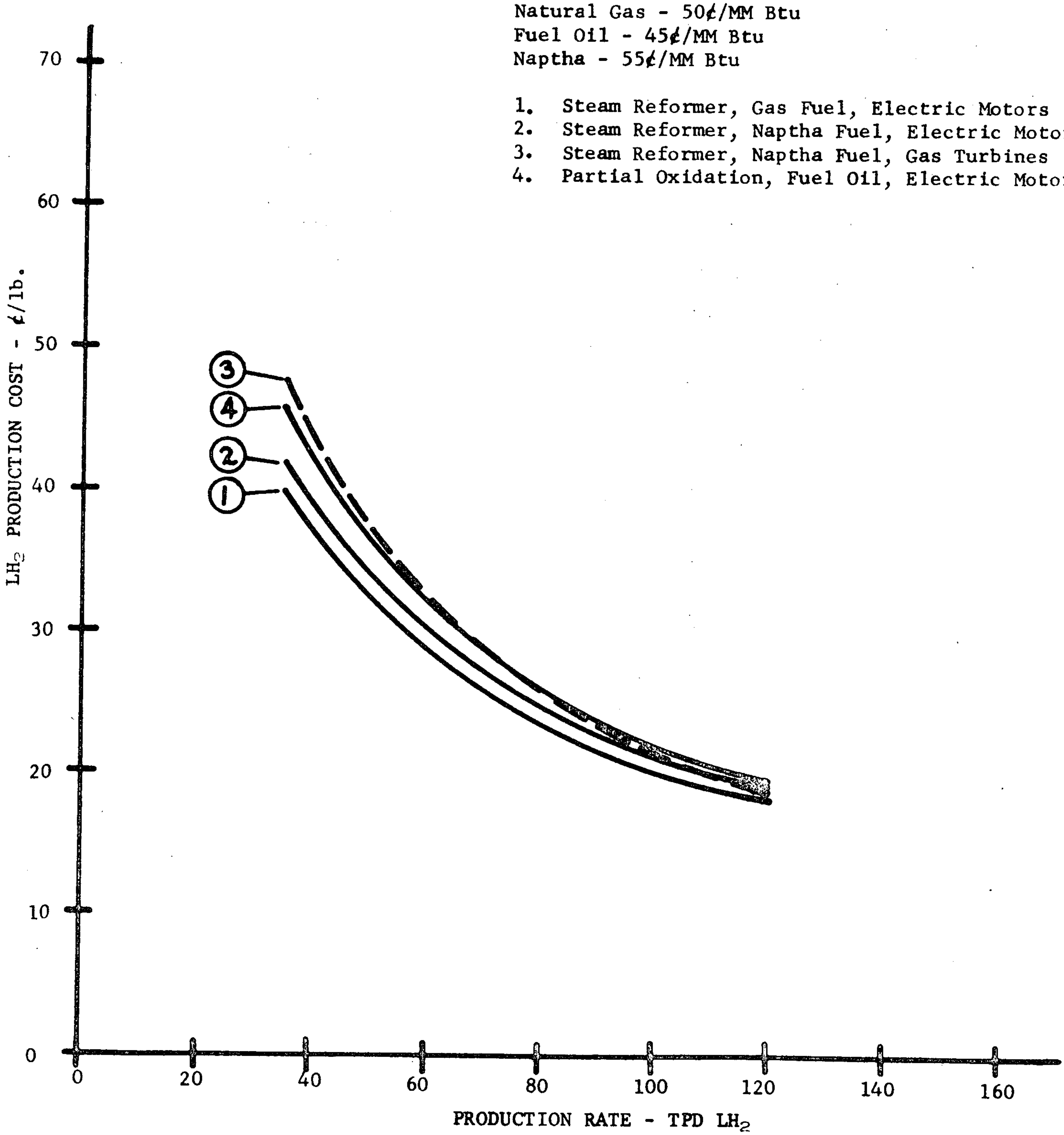


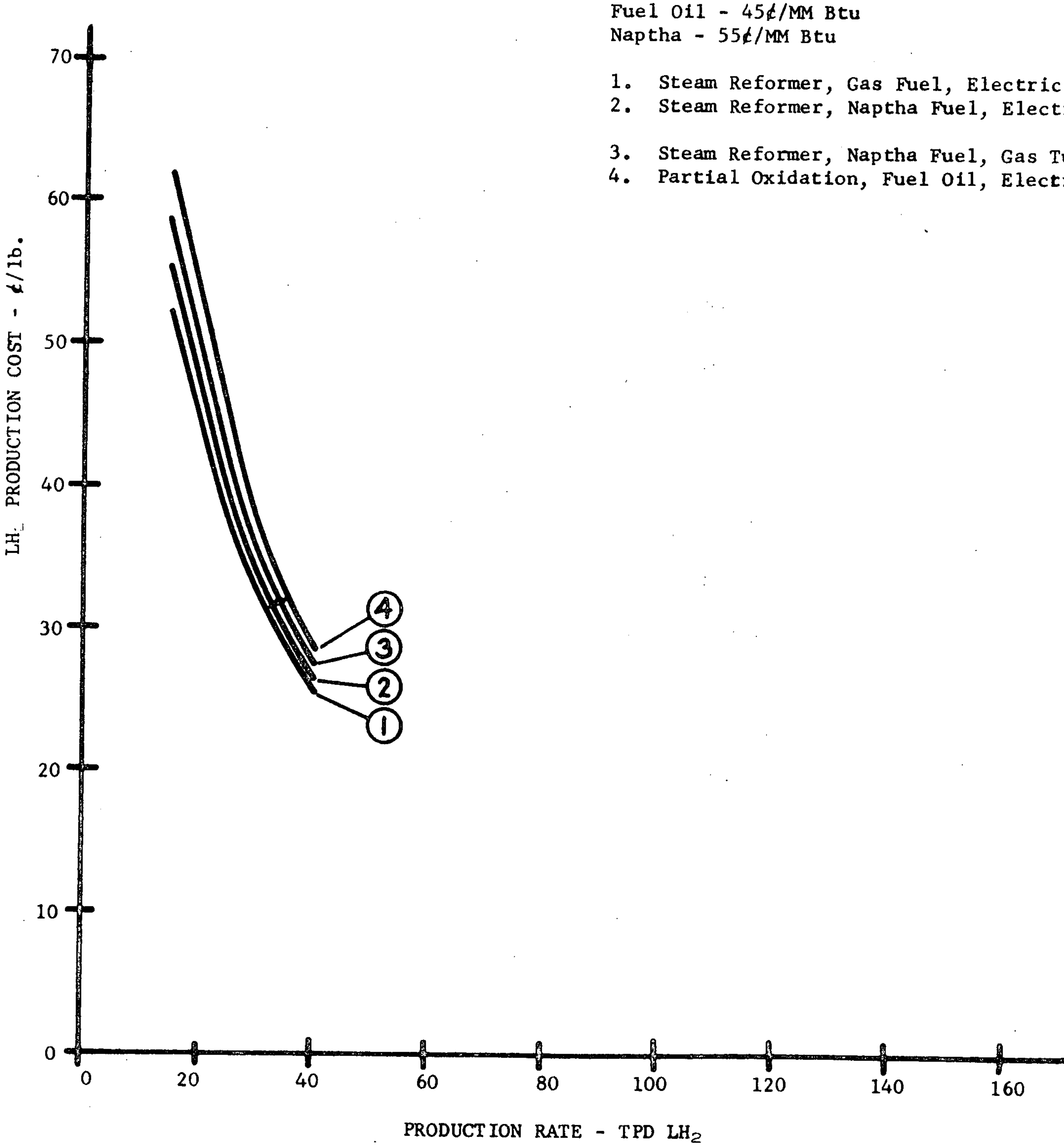
Figure 60

LH$_2$ PRODUCTION COSTS FOR AN INTEGRATED PROPELLANT PRODUCTION PLANT WITH MAXIMUM PRODUCTION CAPABILITY OF 40 TPD LH$_2$, 200 TPD LOX, 100 TPD LIN

BASIS: All costs in 1970 dollars
15-year Contract Period

Power - 0.6¢/KWH
Natural Gas - 50¢/MM Btu
Fuel Oil - 45¢/MM Btu
Naptha - 55¢/MM Btu

1. Steam Reformer, Gas Fuel, Electric Motors
2. Steam Reformer, Naptha Fuel, Electric Motors
3. Steam Reformer, Naptha Fuel, Gas Turbines
4. Partial Oxidation, Fuel Oil, Electric Motors



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close, though higher than the gas turbine drive cases. Figure 59 shows that the longer evaluation period starts favoring the gas turbine drive case in the higher range of production capacity. Once again, the longer evaluation period tends to start favoring the high investment, low operating cost case. As plant utilization drops off, the electric motor drive case starts to become favored again because of its lower investment.

Integrated plant production costs for a 40 TPD integrated plant are presented for the more attractive cases by Figure 60 using a 15-year contract or evaluation period. This production level was arbitrarily chosen to provide an idea as to the impact that the economy of scaleup has on a cryogen producing facility. At this lower production plant size level the electric motor drive cases appear more attractive throughout. For this reason, shorter evaluation periods, which would merely show the lower investment cost electric motor drive cases to look even more attractive, are not shown.

In summary, the following conclusions can be drawn regarding the LH_2 production costs from an integrated propellant manufacturing facility.

1) Plant design capacity and utilization are the two major factors which influence the unit production cost of LH_2. The larger the plant size, the lower the unit production cost due to economies of scaleup in investment and the ability to design a more efficient process. However, if a large plant is not fully utilized the production costs will be greater than from a smaller plant which is fully utilized.

2) Steam reforming is a more attractive route for generating hydrogen than a partial oxidation unit based on the utility costs assumed.

3) The gas turbine drive system is favored for conditions of high production, long evaluation periods and high plant utilization. Electric motor drive is favored for the opposite conditions and all steam turbine drive cases are least attractive.

Changes in the cost of utilities from those assumed for this presentation could alter some of the above conclusions. The following table provides information for determining the impact of possible change on the production costs.

H_2 Generation Process	Fuel	Prime Mover	Change in Unit Production Cost - ¢/#	
			0.1¢KWH Electric	10¢/Million Btu
Steam Reformer	Nat. Gas	Electric Motors	0.73	1.03
Steam Reformer	Nat. Gas	Gas Turbines	0.45	1.29
Steam Reformer	Nat. Gas	Steam Turbines	0.45	1.21
Steam Reformer	Naptha	Electric Motors	0.73	1.13
Steam Reformer	Naptha	Gas Turbines	0.45	1.39
Steam Reformer	Naptha	Steam Turbines	0.45	1.32
Partial Oxidation	Naptha	Electric Motors	0.795	1.08
Partial Oxidation	Naptha	Steam Turbines	0.45	1.44
Partial Oxidation	Naptha	Gas Turbines	0.45	1.34
Partial Oxidation	Fuel Oil	Electric Motors	0.795	1.08
Partial Oxidation	Fuel Oil	Steam Turbines	0.45	1.44
Partial Oxidation	Fuel Oil	Gas Turbines	0.45	1.34

c. Comparison Between Integrated and Non-Integrated Plant Hydrogen Production Costs

Comparisons between integrated and non-integrated plant LH_2 production costs are illustrated by Figures 61 through 64. In all cases, the integrated plant has an advantage of approximately 5%. This is because the integrated plant has a lower relative investment cost and higher overall operating efficiency than its non-integrated counterpart. Detailed inspection of the illustrations will show that the integrated plant's relative advantage becomes slightly greater for smaller plant sizes (see Figure 64 for 40 TPD LH_2 plant comparison), lower utilization and shorter evaluation periods. The production cost advantage of an integrated production facility will exist whether it is located on or off Government property.

d. LNG Integration

Use of LNG permits reducing power by approximately 10,000 KW. However, this savings is more than offset by the premium which must be paid for LNG. LH_2 production costs from a steam reformer system using electric motors

Figure 61

COMPARISON OF COSTS FOR PRODUCING LH_2 FROM INTEGRATED AND NON-INTEGRATED PLANTS WITH MAXIMUM PRODUCTION CAPABILITY OF 160 TPD LH_2

BASIS: All costs in 1970 dollars

Power - 0.6¢/KWH
Fuel Oil - 45¢/MM Btu
Naptha - 55¢/MM Btu

Steam Reformer, Naptha Feed, Fuel Oil for Fuel, Electric Motors

5-year Evaluation Period:
A1 - Non-Integrated
B1 - Integrated

15-year Evaluation Period:
A2 - Non-Integrated
B2 - Integrated

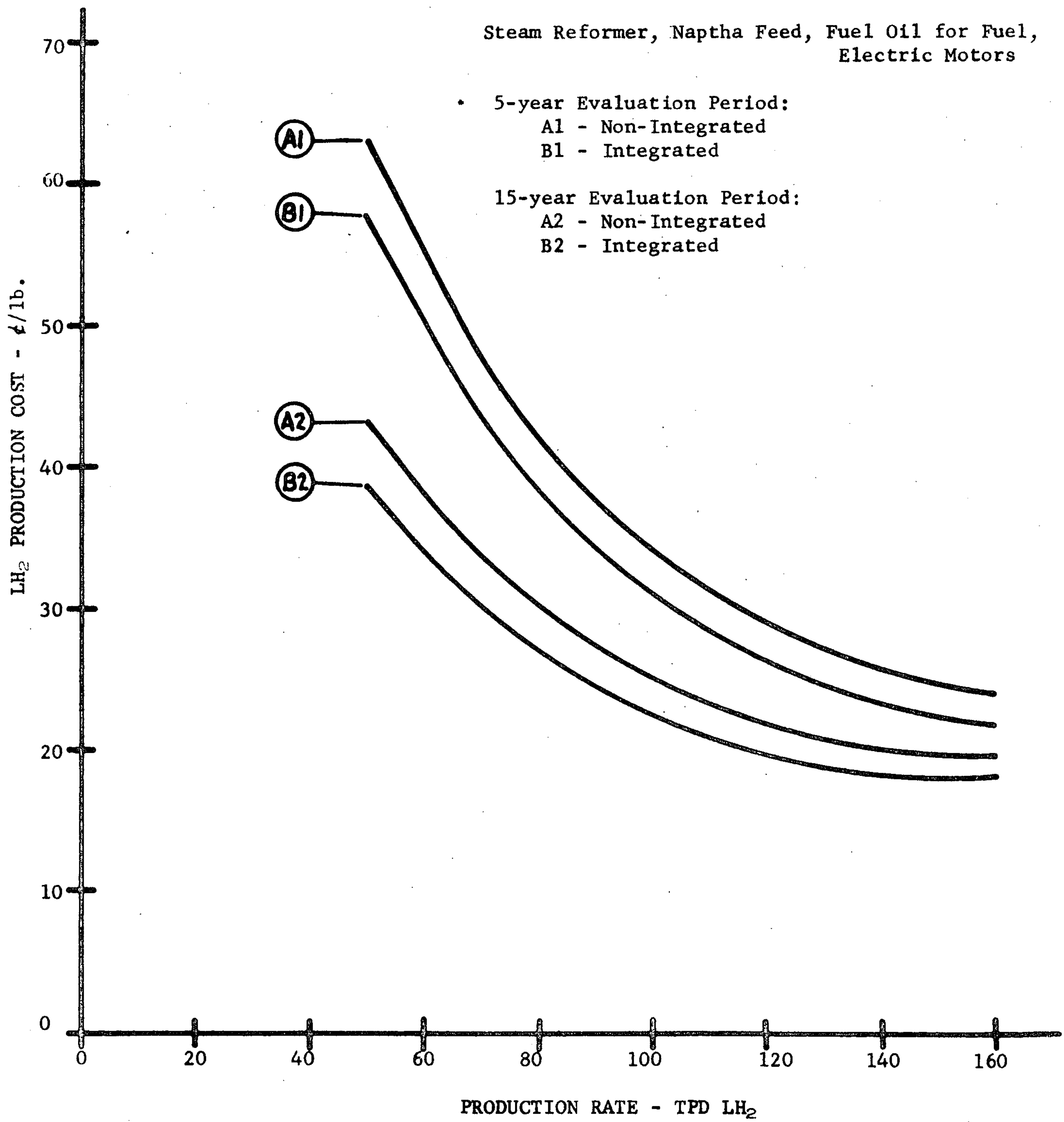


Figure 62

COMPARISON OF COSTS FOR PRODUCING LH_2 FROM INTEGRATED AND NON-INTEGRATED PLANTS WITH MAXIMUM PRODUCTION CAPABILITY OF 160 TPD LH_2

BASIS: All costs in 1970 dollars

Power - 0.6¢/KWH
Fuel Oil - 45¢/MM Btu
Naptha - 55¢/MM Btu

Steam Reformer, Naptha Feed, Fuel Oil for Fuel, Gas Turbines

5-year Evaluation Period:
A1 - Non-Integrated
B1 - Integrated

15-year Evaluation Period:
A2 - Non-Integrated
B2 - Integrated

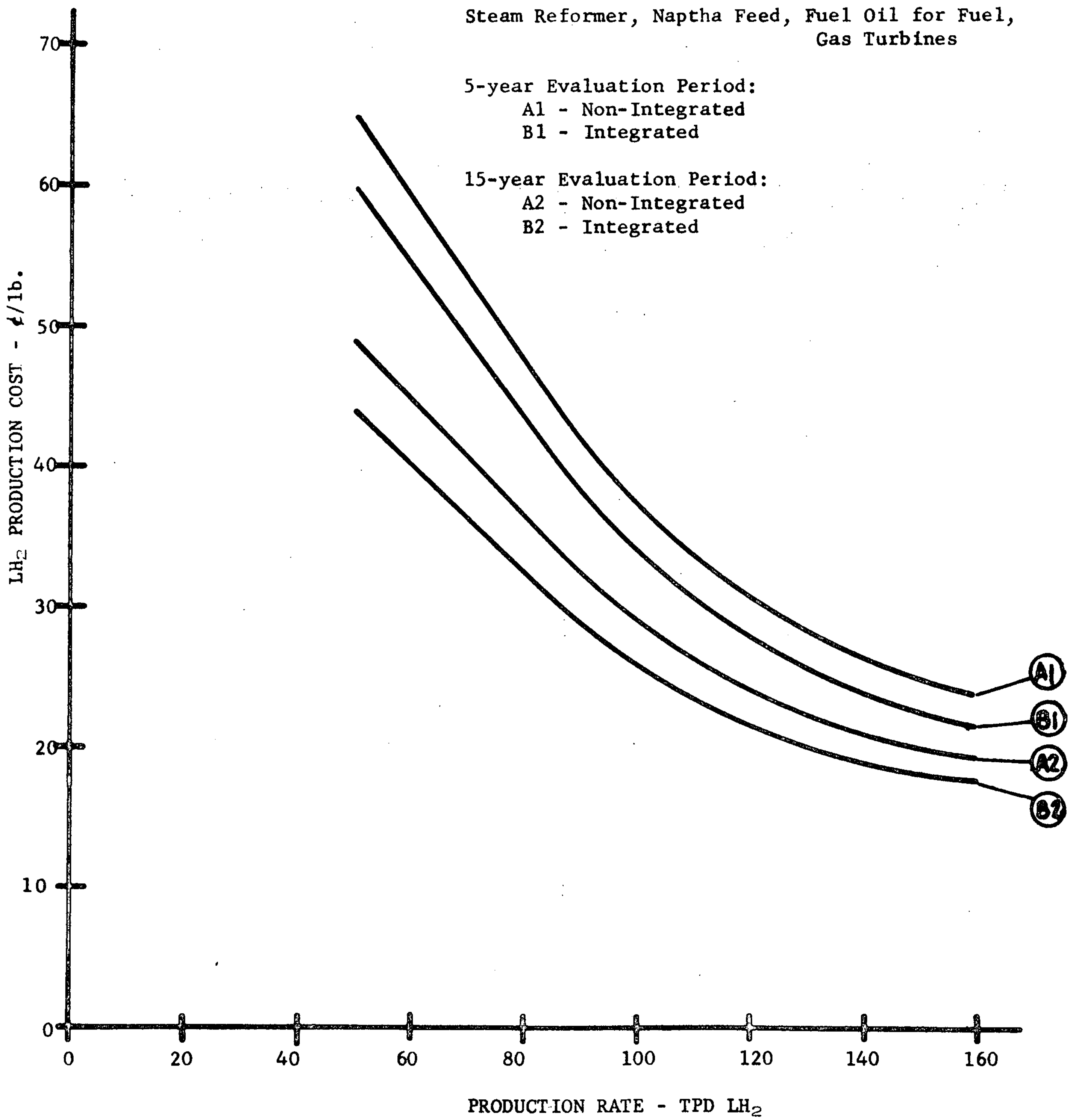


Figure 63

COMPARISON OF COSTS FOR PRODUCING LH_2 FROM INTEGRATED AND NON-INTEGRATED PLANTS

WITH MAXIMUM PRODUCTION CAPABILITY OF 160 TPD LH_2

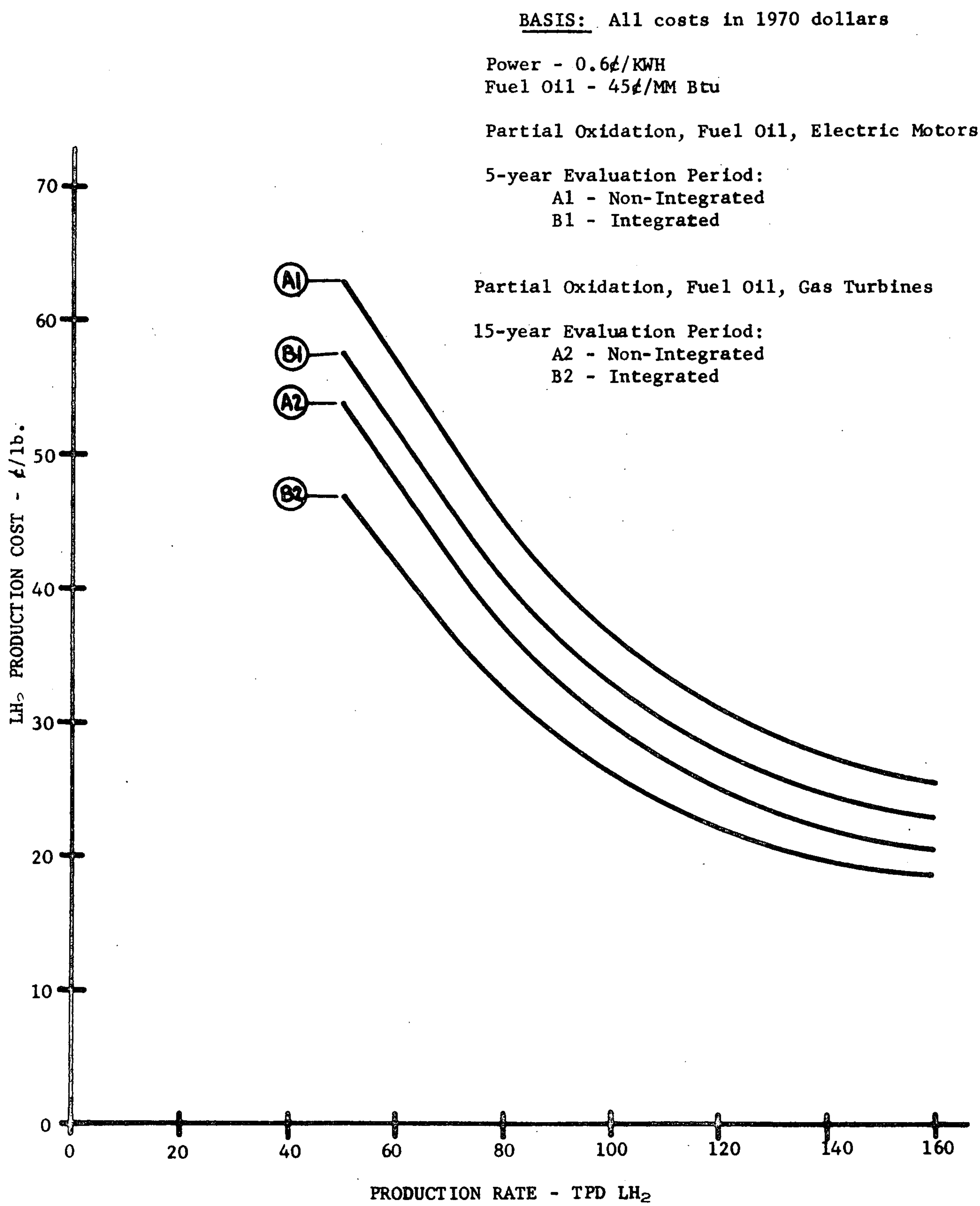
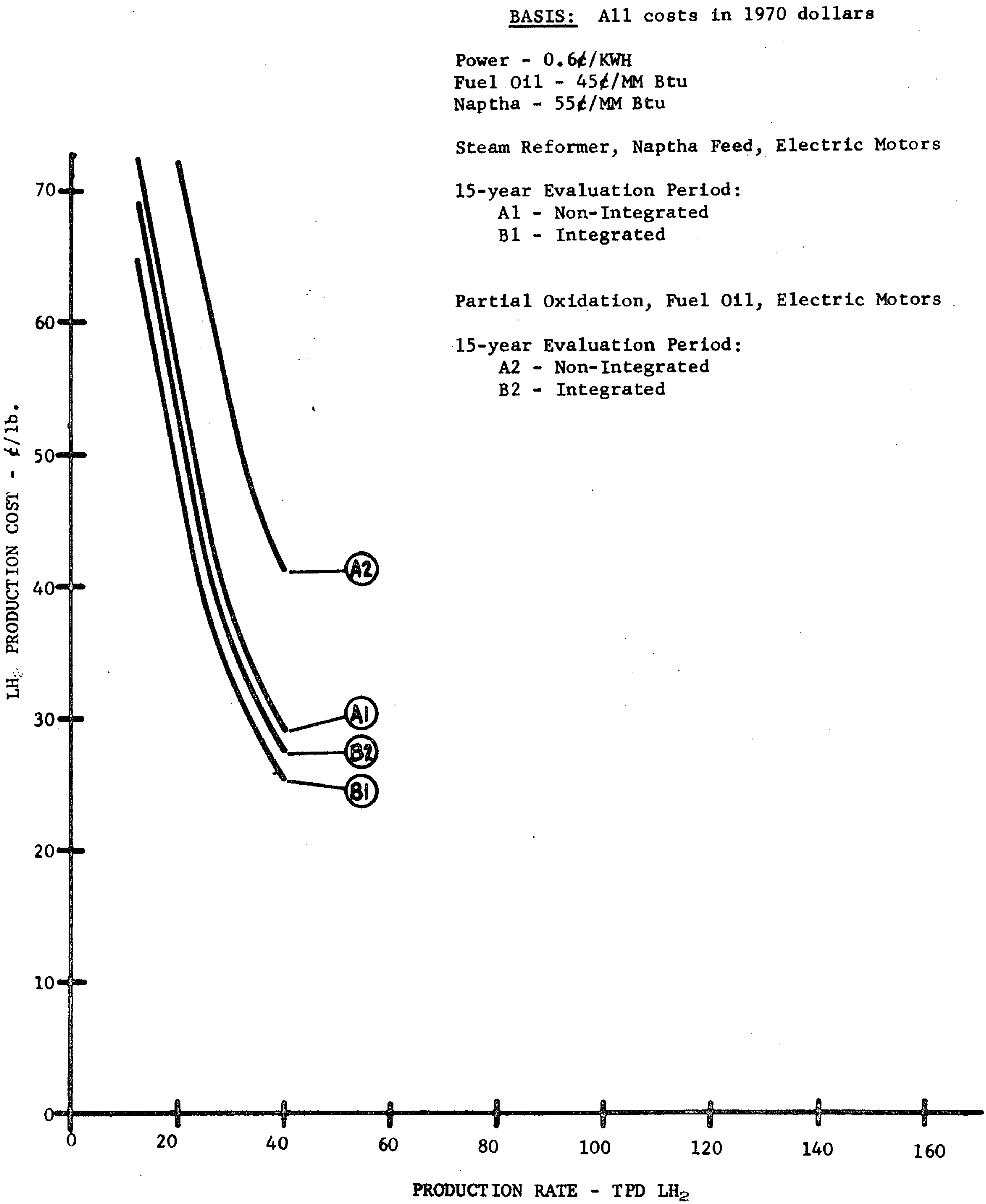


Figure 64

COMPARISON OF COSTS FOR PRODUCING LH_2 FROM INTEGRATED AND NON-INTEGRATED PLANTS WITH MAXIMUM PRODUCTION CAPABILITY OF 40 TPD LH_2



is 20.7¢ per lb. based on a 15-year evaluation or contract period. This compares with 18.0¢ per lb. for a naptha feed counterpart. This difference in production cost plus the uncertainty of the LNG supply picture for the quantity being considered in this study preclude further consideration of LNG.

e. Equipment Redundancy

Based on the information and costs provided on this subject in the first section of this report, the storage alternative is recommended as the best means of assuring a continuing supply of propellants and pressurants at minimum costs. Granted this is not an adequate solution in the event a catastrophic disaster should occur and the entire facility be destroyed but the liklihood of this happening is very small and would not warrant the premium incurred in building two half-sized plants. One consideration which would help add to the potential overall performance reliability would be the inclusion of two half-sized nitrogen recycle compressors. The premium for this redundancy is relatively small and the probability of an extended shutdown due to this machine being damaged is minimized.

f. Contract Cancellation Charges

It is assumed that any contract would be signed with the intent that the contractor receive payment for the depreciation on his committed investment. Thus, the cancellation charges would be determined by simply multiplying the number and/or fraction of years remaining on the contract by 0.20 if a 5-year contract were agreed upon, 0.10 for a 10-year contract or 0.06 for a 15-year contract and then multiplying this product by the initial investment cost of the production facility.

2. Co-Product Opportunities

a. Commercial Liquid Hydrogen, Oxygen, and Nitrogen

Commercial opportunities do exist for liquid hydrogen, oxygen, and nitrogen which could be serviced from a plant located in the KSC area. Figures 65 to 67 were prepared to demonstrate the effect that commercial sales of these products would have in reducing the cost of producing LH_2 for the government for various size plants operating at reduced production levels. All credits have been allocated to the cost of producing the LH_2. Two principal observations can be made. The first is that sales of commercial products increase the plant utilization which results in allocating the fixed depreciation and interest charges to a greater quantity of product thereby reducing the unit costs. The greater these commercial sales, the greater this effect will be. The second observation is that the same level of commercial product sales will have the greatest relative effect on the smallest size production plant.

Figure 65

Reduction in LH_2 Production Cost Due to Commercial Sales of

LH_2, LOX, & LIN for an

Integrated Propellant Plant with Maximum Production Capacity of 160 TPD LH_2

Basis: 5-Year Contract Period

A. 2 TPD LH_2, 10 TPD LOX, 5 TPD LIN

B. 10 TPD LH_2, 50 TPD LOX, 25 TPD LIN

C. 20 TPD LH_2, 100 TPD LOX, 50 TPD LIN

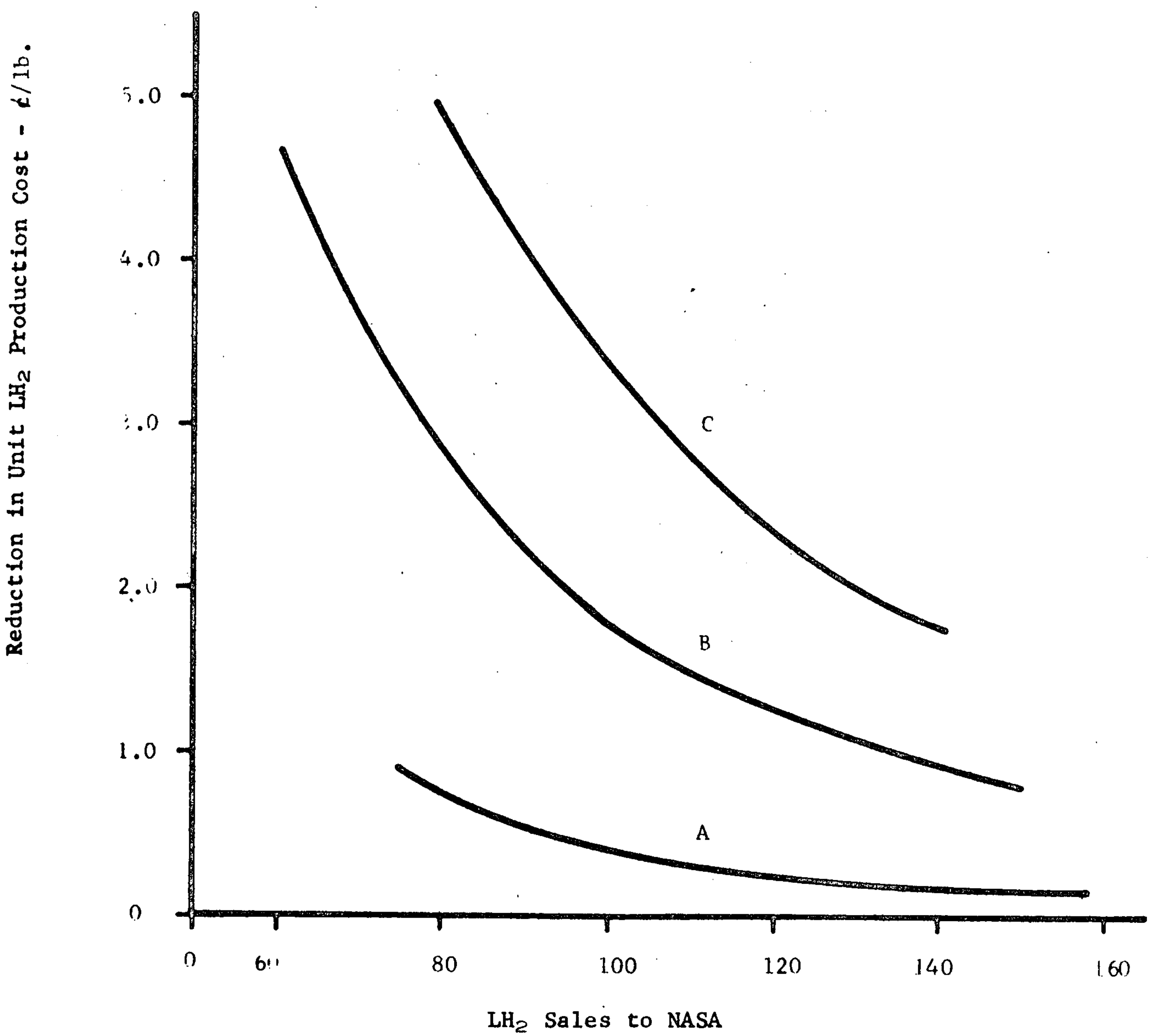


Figure 66

Reduction in LH_2 Production Cost Due to Commercial Sales of LH_2, LOX, & LIN for an Integrated Propellant Plant with Maximum Production Capacity of 120 TPD LH_2

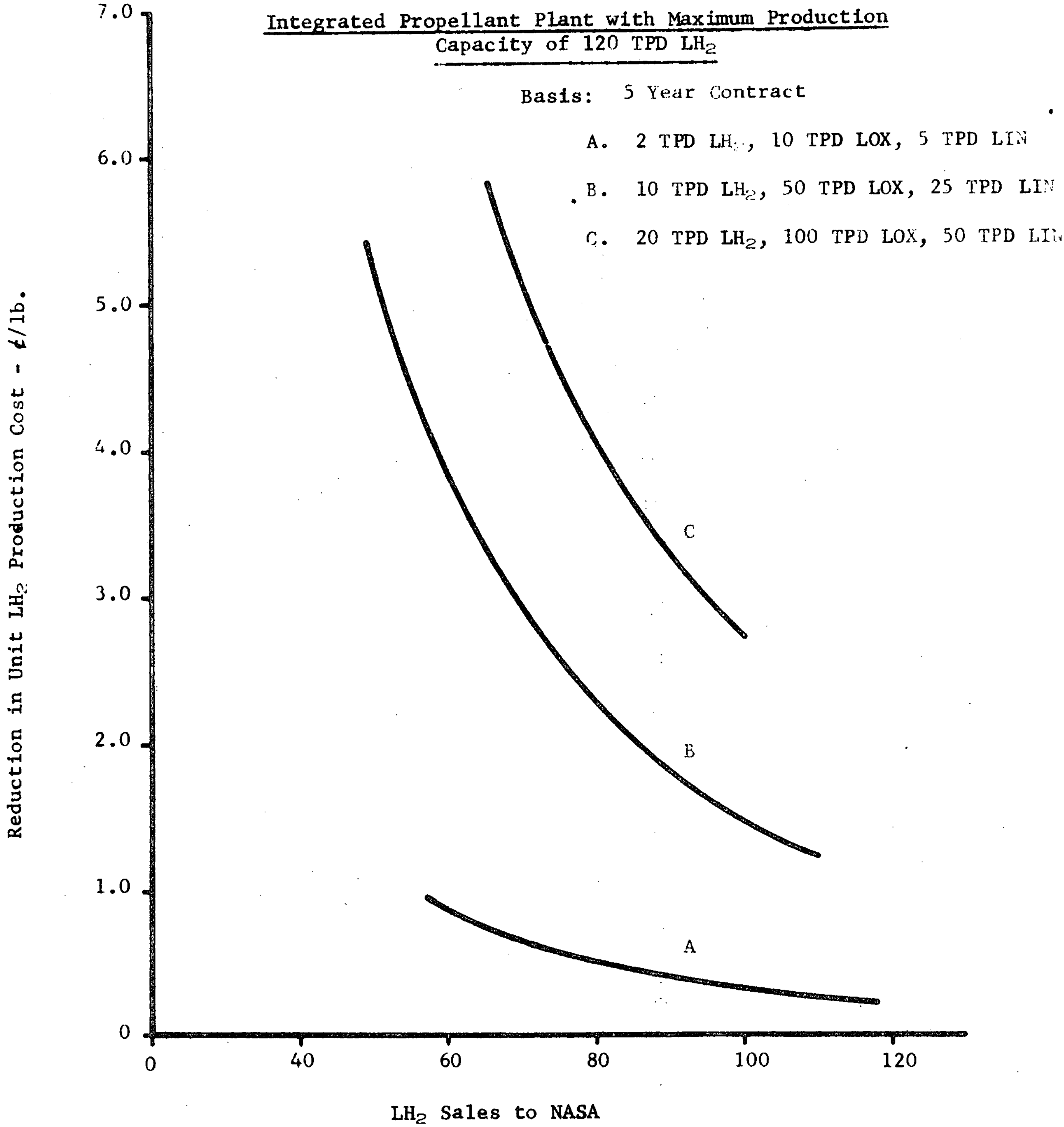


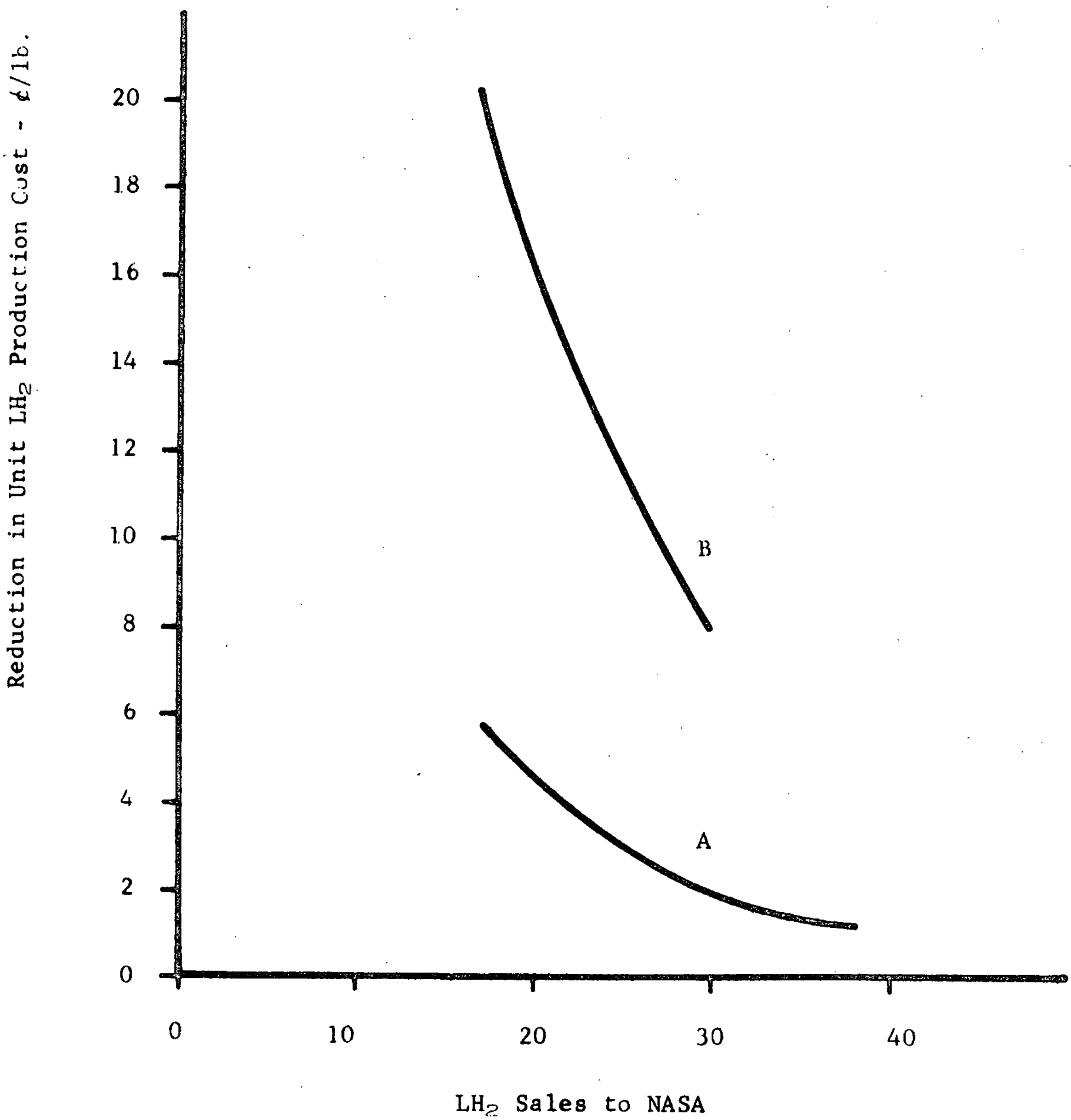
Figure 67

Reduction in LH_2 Production Cost Due to Commercial Sales of LH_2, LOX & LIN for an Integrated Propellant Plant with Maximum Production Capacity of 40 TPD LH_2

Basis: 5 Year Contract

A. 2 TPD LH_2, 10 TPD LOX, 5 TPD LIN

B. 10 TPD LH_2, 50 TPD LOX, 25 TPD LIN



b. Deuterium

A \$10 per pound price differential between the production cost and market price of deuterium would have the result of lowering LH_2 production cost by 1.17¢ per pound if the profit from making the deuterium were credited to the hydrogen. Examination of Figure 41 indicates the difference between the cost of making deuterium oxide based on a 15-year contract period and the World Market price is \$12.30 per pound at full production capacity. Thus, the LH_2 price would be lowered by \$1.44 per ton, based on the assumptions employed, if deuterium were produced. This would reduce the cost of making 140 TPD LH_2 from a 160 TPD integrated LH_2 plant to 17.56¢/lb. (steam reformer, naptha feed, gas turbines, 15-year evaluation period) compared with 19¢/lb. without the credit. This would compare with a unit cost of 17.4¢/lb. when producing 160 TPD LH_2 and no deuterium from an integrated plant. If a 5-year evaluation period were used to evaluate the deuterium, the LH_2 production cost after adding the deuterium production credit would be 17.8¢/lb. It should be emphasized that deuterium production definitely is contingent on hydrogen being produced. That is to say that if only 100 TPD of LH_2 were required, the deuterium recovery facility could be only 100/140 or 71.5% utilized. The credit for deuterium recovery would then have to be computed on this basis. To minimize the requirement for such computations, Figure 68 presents a plot showing the potential reduction in LH_2 production costs due to deuterium credits as a function of plant utilization for 5 and 15-year contract periods.

c. Methanol Production

Methanol production costs have been developed (Figure 43) on the basis that the LH_2 production plant would be used as much as possible and only the additions to generate the methanol are considered part of the methanol production costs. Using a methanol price of 14.5¢ per gallon, the impact of methanol generation on the cost of producing LH_2 is presented as a function of plant utilization for producing LH_2 for an integrated 160 TPD LH_2 plant by Figure 69. This graph indicates that if the LH_2 plant utilization for producing LH_2 is 80% or greater, methanol addition has no value. At lower utilization levels, the methanol co-product addition would help lower the unit hydrogen production costs. For purposes of illustration, consider 50% utilization of the LH_2 production plant. This would correspond to an LH_2 production of 80 TPD compared with the design capacity of 160 TPD. At this level of the LH_2 plant utilization, the impact of crediting the profit generated by methanol production to LH_2 production would be 1.8¢/lb. of LH_2. This would lower the LH_2 production costs from 28¢/lb. to 26.2¢/lb. (steam reformer, naptha feed, gas turbines) which would compare with a 17.4¢/lb. production cost if the LH_2 plant were totally utilized, making 160 TPD of LH_2.

From the above, it can be concluded that the addition of a methanol unit in the circumstance of low LH_2 plant utilization could help reduce the LH_2 production costs. However, this impact is not great enough to offset the strong influence that low utilization has on increasing the LH_2 production

Figure 68

Reduction of LH_2 Production Costs Due to Co-Production of Deuterium Oxide (D_2O)

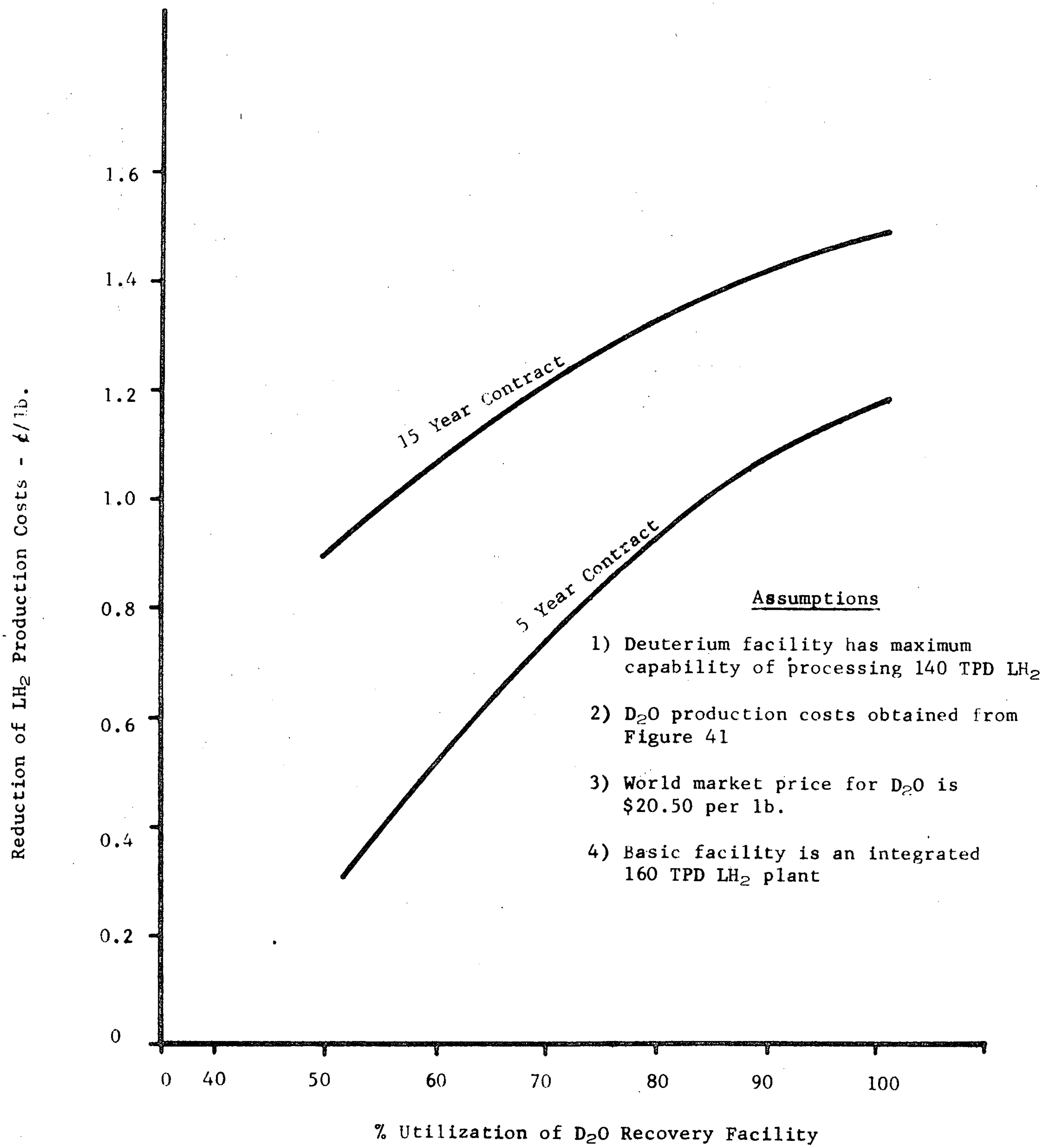
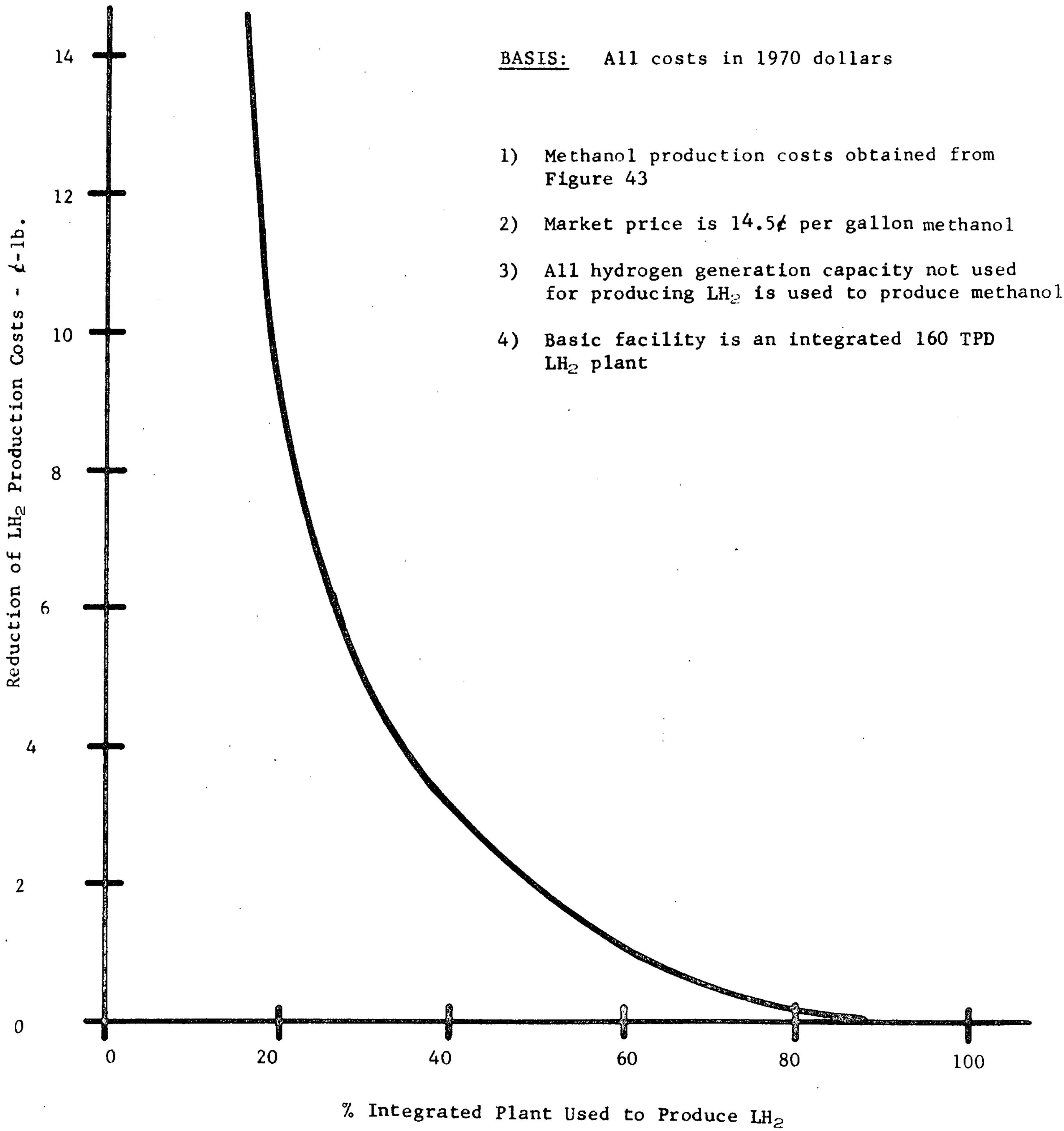


Figure 69

Reduction of LH_2 Production Costs Due to

Co-Production of Methanol



costs. It should also be pointed out that the above analysis is sensitive to the market price of methanol. A lower price would decrease its benefits to LH_2 production cost and a higher price would have the opposite affect. At present, the methanol market is quite strong and it would be anticipated that future prices would have a tendency to decrease rather than increase. Two final important considerations should also be mentioned. First, it may prove difficult to market all methanol produced from a facility such as this located at KSC which does not benefit from the presence of a nearby petrochemical complex requiring a baseload quantity of methanol. Secondly, it is emphasized that once the investment is committed to making methanol, it must be fully utilized in order to recover its projected value. That is to say that full LH_2 production could not again be resumed without a substantial loss being incurred by the subcontractor on the methanol production.

d. Ammonia Production

Ammonia costs were developed on the basis that no LH_2 product would be required and all H_2 and N_2 production would be used to generate ammonia. This would result in the lowest ammonia production costs. As was the case when considering methanol production, only the additions needed to generate the ammonia are considered part of the ammonia production costs. On this basis, the ammonia production cost proved to be approximately $25/ton which is greater than the current market price of around $20/ton for large quantities of ammonia. There are three principal reasons for this unfavorable comparison. First, commercial ammonia plants are efficient, tailor made, single train processes designed specifically to produce ammonia. A LH_2 production plant, converted to make ammonia suffers by comparison even though a sizable portion of the overall investment is considered free in this evaluation. Secondly, fuel costs are lower in the Gulf Coast area where the greatest quantity of ammonia is generated. This is because the principal source of natural gas is the Gulf Coast area. Gas used in other areas would have to be pipelined from the Gulf Coast and consequently the transmitted gas would have to bear the interest and amortization cost of a pipeline. Use of other possible fuels would not suffer from this handicap, however, these fuels are normally priced on the basis of the local area natural gas price. One could argue that the premium incurred in transporting fuel will be offset by permitting the ammonia producing facility to be located nearer the ultimate ammonia use point, thereby lowering the ammonia product shipment costs. In some instances, this is a valid argument. However, in this instance, the KSC area is as far away from Tampa, which is the major ammonia consuming area in Florida, as the Gulf Coast ammonia plant if the normal barging mode of transportation is employed.

The third reason for the unfavorable comparison between the current ammonia market price and the converted KSC LH_2 ammonia generating plant costs is that the current ammonia market is suffering from overcapacity and the market is very weak. At $20/ton it is doubtful that ammonia producers are making sufficient return on investment to permit reinvesting in additional facilities. Thus it would be anticipated that in the next few years, the ammonia market should strengthen and the price increase. It is doubtful, however, that the price will rise above $25/ton which would indicate that ammonia is not an attractive co-product for consideration at the KSC location.

3. Evaluation of Transport Methods

Transport costs were evaluated to determine the most economical mode of transport for liquid hydrogen, liquid oxygen, and liquid nitrogen from integrated propellant plants designed to produce 160 TPD, 120 TPD, and 40 TPD of liquid hydrogen. A subjective evaluation of the different modes of transportation considered is presented in Figure 70, appended. The economics of four cases were studied in detail.

a. Trucking

A general site within twenty miles of pad 39B was used as the basis of developing trucking costs. Port Canaveral, NASA Sites #1 & #2 and the East Coast of Florida are all included within this perimeter. Round trip time in this area is four hours. A conceptual drawing illustrating this mode of transport is shown by Figure 71.

The investment cost, operating cost, and evaluated cost for 5-year and 15-year contracts for trucking are given in Figure 72, appended.

b. Rail

A general site on the East Coast of Florida near the Florida East Coast railroad was chosen as the basis for this case. Round trip by special train is five hours. The cost of a rail siding at pad 39B is $400,000. Since product losses in rail shipment (7%) are less than for trucks (8%) the integrated propellant plant can be sized 1% smaller and both an investment and an operating cost saving is achieved. The costs for rail transport are given in Figure 73, appended. This delivery concept is similar to truck transport, shown in Figure 71.

c. Barges

The barging costs developed are based on the ten hour round trip from Port Canaveral to 39B. To barge to pad 39B from Port Canaveral a channel must be dredged from the vicinity of pad 39A to pad 39B. Also, 1,500 feet of vacuum jacketed liquid hydrogen piping and 3,000 feet of liquid oxygen and liquid nitrogen piping must be installed. Since product loss due to barging (7%) is 1% less than the trucking loss, the investment cost and operating cost of the integrated propellant plant can be reduced. Figure 74 illustrates this mode of transport.

Figure 75, appended, presents the barging evaluation if the MTF barges are available. Figure 76, appended, presents the costs if new barges must be purchased. Barging costs were also investigated for the Florida East

CRYO DELIVERY & STORAGE SYSTEM - Truck Transport

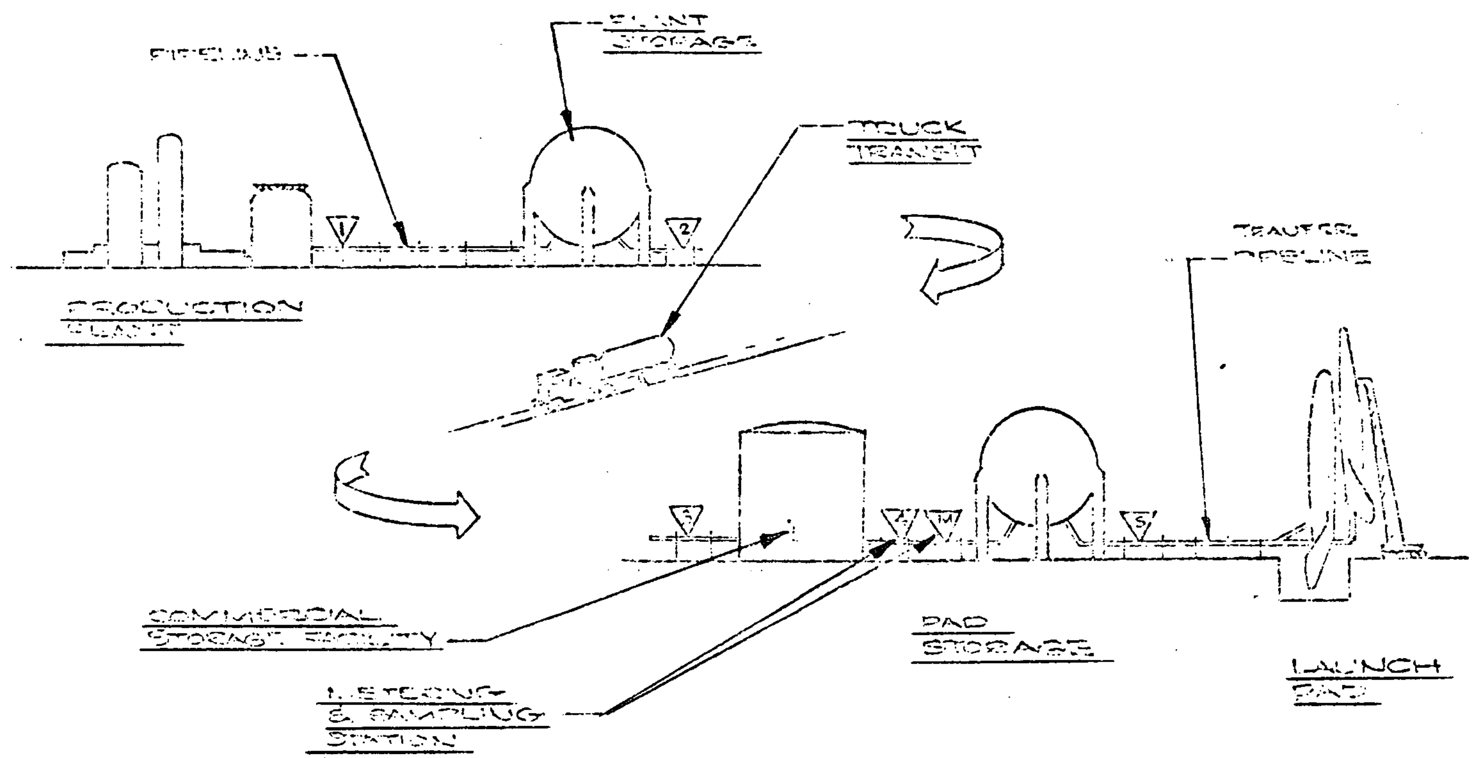


FIG. 71

▽ SAMPLING STATIONS

CRYO DELIVERY & STORAGE SYSTEM - Barge Transport

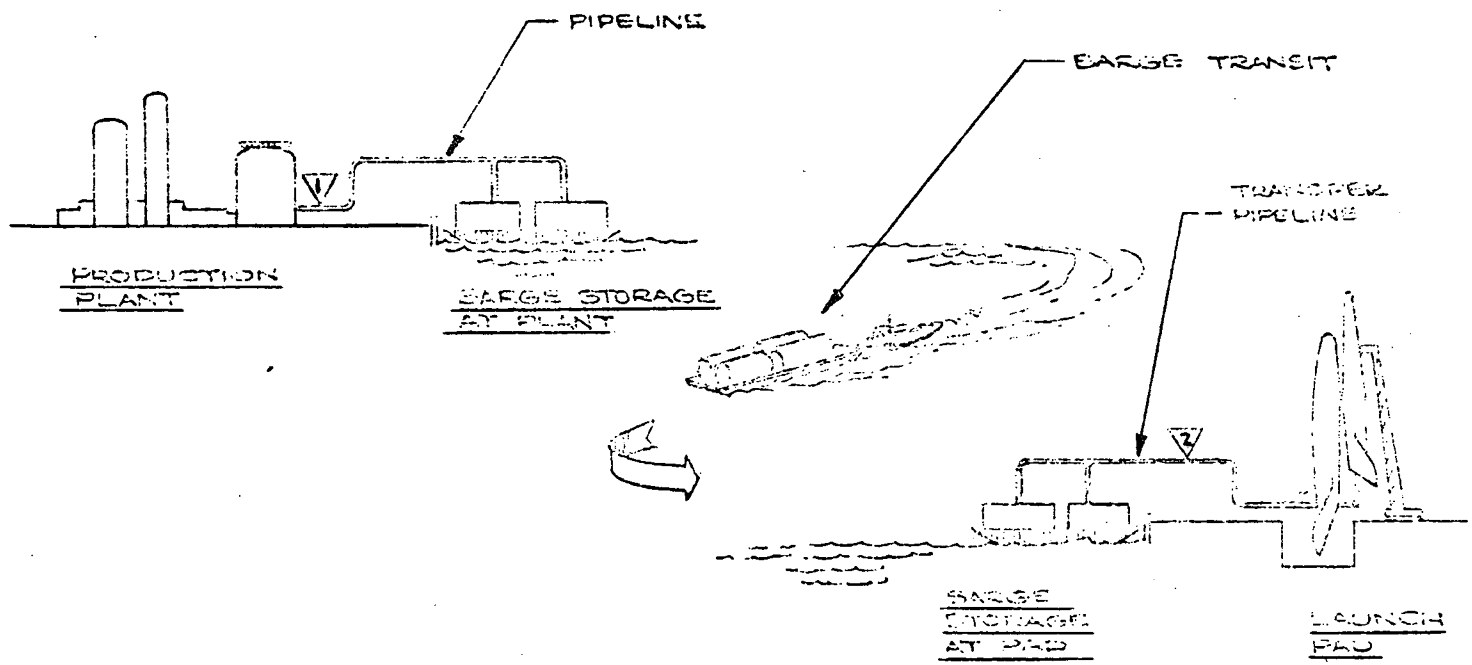


FIG. 74

▽ SAMPLING STATIONS

Coast Site using the MTF barges. Round trip time is 20 hours. This mode of transportation proved more expensive than rail transport and consequently, its costs are not presented.

d. Vacuum Insulated Piping

The costs for installing the 20,000 feet of liquid hydrogen pipe and 18.000 feet of liquid oxygen and liquid nitrogen pipe from NASA Sites #1 and #2 are given in Figure 77, appended. Figure 78, appended, presents costs for 5,600 feet of vacuum jacketed pipe. Since the losses in the vacuum jacketed pipe are 5%, there is a savings in the integrated propellant plant. Figure 79 is a drawing of the vacuum insulated pipeline concept.

e. Mixed Transport Modes

The only instance where savings occur by mixing transport modes is in combining LH_2 and LOX VIP with LIN trucking from NASA Site #1 and NASA Site #2. Combinations using barging and rail transport were considered. However, the fixed cost of dredging, in the case of barging, and a rail siding, in the case of rail transport, precludes the transportation of only one product by these means.

Figures 80 and 81 graph annual operating costs vs. plant capacity for 5 and 15-year contract periods. These graphs will be discussed further in Section III, B.5.

f. Transport of Naptha

If a site other than Port Canaveral is selected, additional naptha handling and storage is required. Naptha must be shipped to Port Canaveral, stored in tanks, and barged to the site where more tankage is required. To determine the cost penalty to a site due to the additional handling of feed for an all electric drive plant, a general site was selected that is within a ten hour barge turn-around from Port Canaveral. This perimeter includes all the sites previously discussed.

Based on one week storage for naptha and barges of 100,000 gallons capacity the following additional equipment is required if the plant is not located at Port Canaveral.

LH_2 Production, TPD	Barges Required	Naptha Storage, Gallons
160	2	2,000,000
120	2	1,500,000
40	1	500,000

Barges cost $216,000 each and naptha storage costs 6-1/2¢ per gallon.

CRYO DELIVERY & STORAGE SYSTEM - Vacuum Insulated Pipe

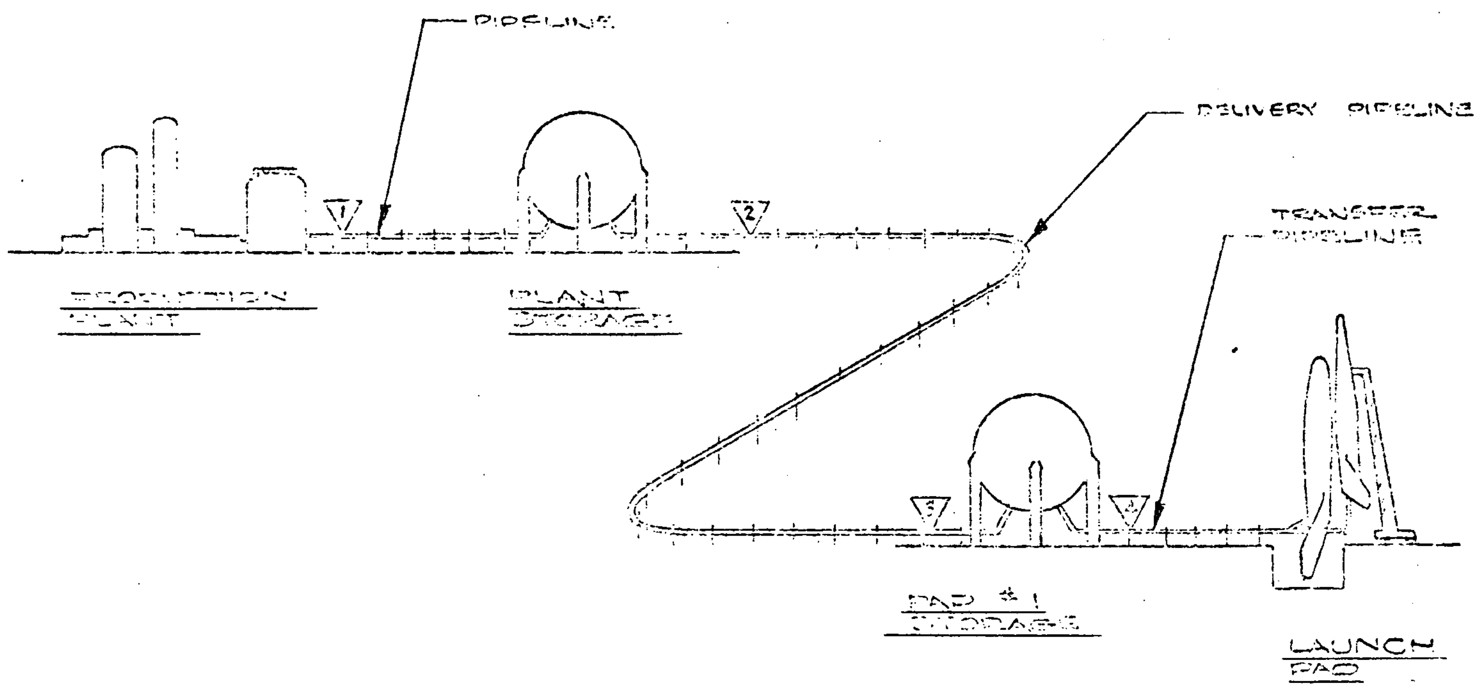


FIG. 79

▽ SAMPLING STATION

The following table summarizes the cost of the additional naptha handling. No dredging costs are included.

LH_2 Production, TPD	Investment	Annual Operating Cost,$/yr.	Total Annual Cost, $/yr. 5-yr.Contract	15-yr.Contract
160	$562,000	$483,000	$ 668,000	$ 594,000
120	530,000	362,000	537,000	466,000
40	249,000	121,000	203,000	170,000

4. Storage Requirements

a. Pad Storage

The recommended minimum storage of ten days production should be located at the launch pad. Ten days storage was chosen because it represents the maximum time the integrated propellant plant might be out of service due to normal equipment failure. This amount of storage also guarantees that there is no bottleneck in product shipment due to full pad storage. The suggested pad storage concept is shown by Figure 71. Since low pressure liquid hydrogen tankage is less expensive than high pressure tankage (Figure 45), this scheme is advantageous because it utilizes a large low pressure tank and permits sizing of the NASA high pressure tank for a one launch capacity. Further savings in time and personnel accrue as the operations of the plant, the delivery system, and the pad commercial storage may be under the control of one contractor, eliminating several interfaces and potential conflicting responsibilities. The commercial storage facility is an extension of plant storage and the product is "sold" on demand to the customer at sampling station 4 and metered through a short pipeline into pad storage tanks. This concept also permits 24-hour access to pad storage by the contractor.

The low pressure tankage required at the pad for ten days storage and prices are given below. These storage costs are additive to the production cost figures given previously.

Product	Number of Tanks	Total Gallons	Capital Cost
LH_2	6	6,000,000	$6,000,000
LOX	1	1,700,000	940,000
LIN	1	1,200,000	740,000
		Total Cost	$7,680,000

b. Plant Storage

It is also recommended that two days storage be located at the propellant plant. This storage is sufficient to balance any swings in production of the propellant facility due to operational problems. The costs of this tankage is summarized in the table below and is included in the estimate of the basic production plant costs presented previously.

Product	Number of Tanks	Total Gallons	Capital Cost
LH_2	1	1,100,000	$1,100,000
LOX	1	340,000	310,000
LIN	1	240,000	260,000
		Total Cost	$1,670,000

c. Transport Storage

Consideration was given to using the transport vehicle as a means of pad storage. This concept is represented by Figure 74 for barge storage. A low pressure liquid hydrogen tank installed on land costs roughly $1 per gallon.

Barge capacity costs about $3.70 per gallon. Rail and truck storage cost much more. Therefore, the most economical type of storage is land based.

5. Evaluation of Sites

The costs previously developed for the transport of feed and product can be combined with the specific site costs to give a total site cost. The following paragraphs present site costs, possible means of transport, and the selected means of transport.

a. Sites Located on Government Property

1. NASA Site #1

Possible means of product transport from this site are truck and vacuum jacketed pipe. Feed must be barged from Port Canaveral and then pumped via pipeline to storage. For a 5-year contract period, transport of LH_2 and LOX by vacuum insulated piping and delivery of LIN by trucking is the best means of product transport from an integrated plant producing more than 100 TPD LH_2 and corresponding amounts of LOX and LIN. Below this capacity, trucking is the preferred means of product delivery, as shown by Figure 80. For a 15-year contract period, Figure 81 indicates that vacuum insulated piping for transport of LH_2 and LOX and trucking LIN is preferred for shipment of quantities greater than 60 TPD LH_2 and corresponding LOX and LIN. Figure 82, appended, summarizes the combined site and transportation costs for this site.

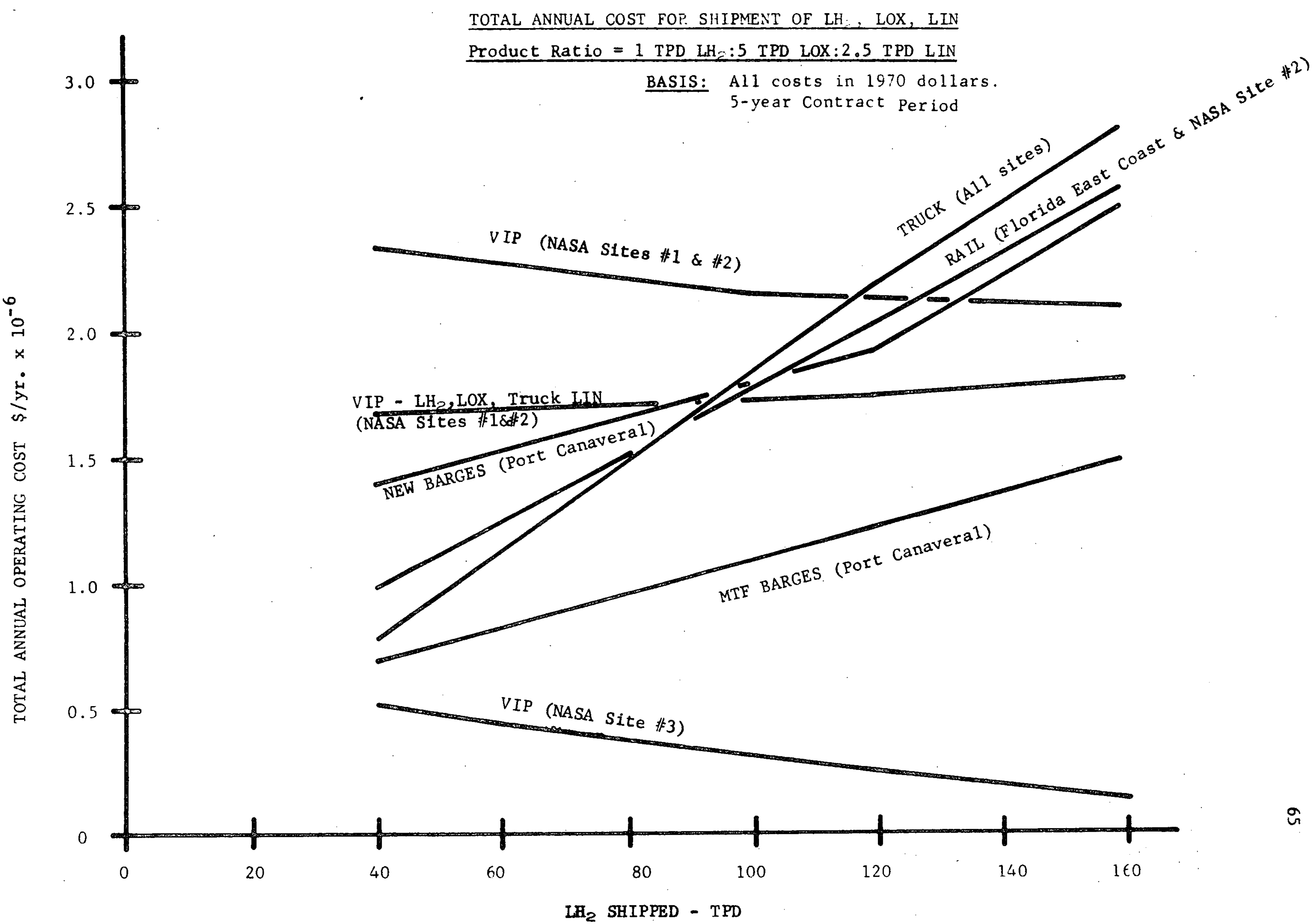

TOTAL ANNUAL COST FOR SHIPMENT OF LH_2, LOX, LIN
Product Ratio = 1 TPD LH_2:5 TPD LOX:2.5 TPD LIN
BASIS: All costs in 1970 dollars.
5-year Contract Period
TRUCK (All sites)
RAIL (Florida East Coast & NASA Site #2)
VIP (NASA Sites #1 & #2)
VIP - LH_2,LOX, Truck LIN
(NASA Sites #1&#2)
NEW BARGES (Port Canaveral)
MTF BARGES (Port Canaveral)
VIP (NASA Site #3)
TOTAL ANNUAL OPERATING COST $/yr. x 10^{-6}
3.0
2.5
2.0
1.5
1.0
0.5
0
0
20
40
60
80
100
120
140
160
LH_2 SHIPPED - TPD

Figure 80

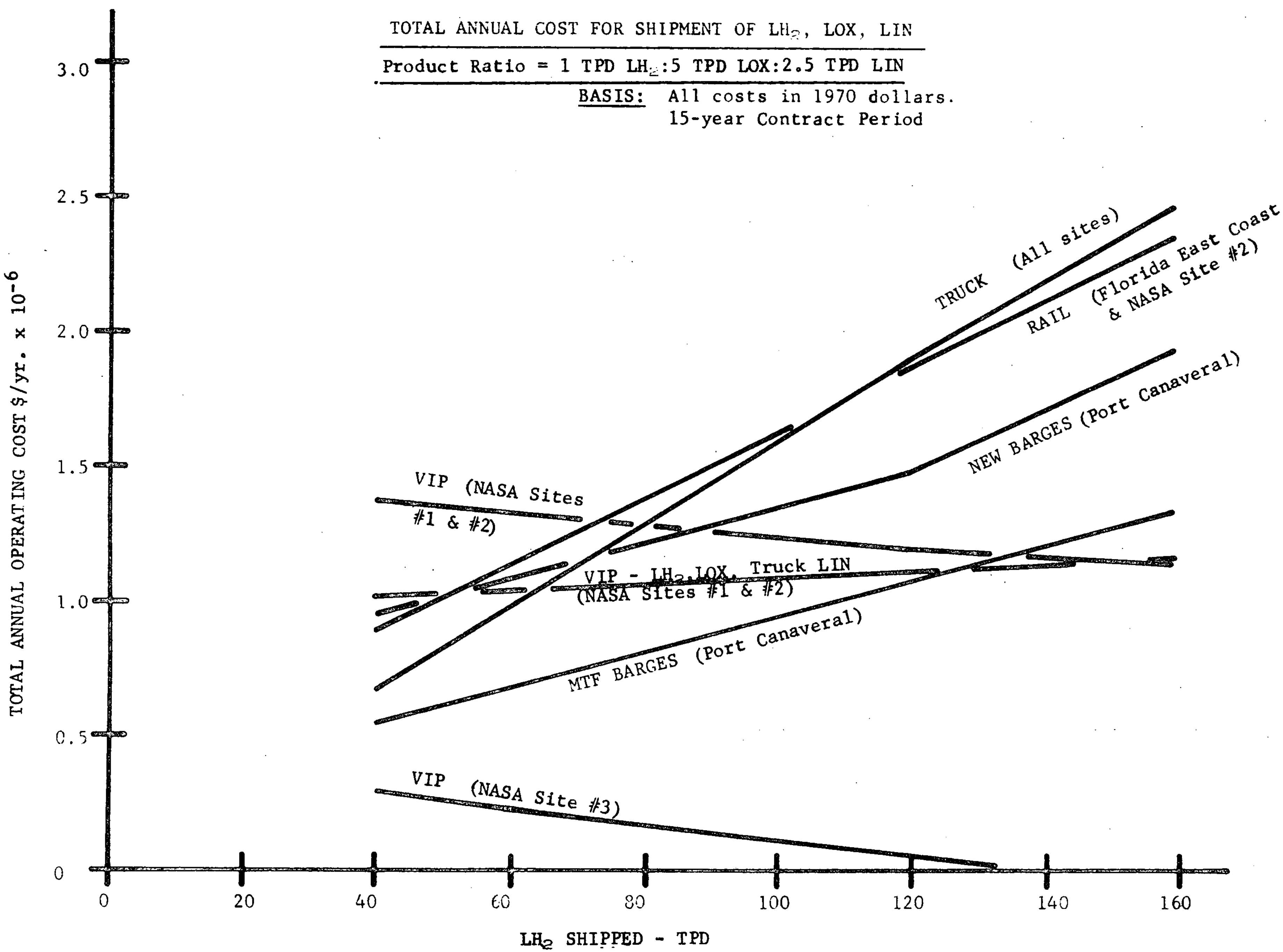

TOTAL ANNUAL COST FOR SHIPMENT OF LH2, LOX, LIN
Product Ratio = 1 TPD LH2:5 TPD LOX:2.5 TPD LIN
BASIS: All costs in 1970 dollars.
15-year Contract Period
TRUCK (All sites)
RAIL (Florida East Coast & NASA Site #2)
NEW BARGES (Port Canaveral)
VIP (NASA Sites #1 & #2)
VIP - LH2,LOX, Truck LIN (NASA Sites #1 & #2)
MTF BARGES (Port Canaveral)
VIP (NASA Site #3)
TOTAL ANNUAL OPERATING COST $/yr. x 10^-6
3.0
2.5
2.0
1.5
1.0
0.5
0
0
20
40
60
80
100
120
140
160
LH2 SHIPPED - TPD

Figure 81

2. NASA Site #2

Possible means of product transport from this site are rail, truck, and VIP. Feed must be barged from Port Canaveral to the VAB turning basin and then pumped to Site #2 storage. Figures 80 and 81 show that for 5 and 15-year contract periods, respectively, the same conclusions as those drawn for NASA Site #1, above, can be made. Figure 83, appended, summarizes the combined site and transportation costs for this site.

3. NASA Site #3

This is a general site located within 5,600 feet of pad 39B. Possible means of product transport are truck and vacuum jacketed pipe. Feed is barged in from Port Canaveral and then pumped to storage. Figures 80 and 81 show that vacuum jacketed pipe has the lowest annual cost for both a 5 and 15-year contract life. Figure 84, appended, gives the total costs for this site.

b. Sites Located off Government Property

1. Port Canaveral

Possible means of product transport from Port Canaveral are truck and barge. Naptha is unloaded directly from the transporting ship. Figures 80 and 81 show that barging using the existing MTF barges is the lowest cost transport method. Figure 85, appended, summarizes the total costs for this site.

2. Florida East Coast Site

This site is adjacent to the Florida East Coast railroad on the Florida mainland. The means of product transport considered are rail, barge, and truck. Naptha must be barged from Port Canaveral. Rail transport is the most economical means of transport for propellants at a liquid hydrogen production of 160 TPD and 120 TPD LH_2 and corresponding amounts of LOX and LIN. At 40 TPD, truck transport provides the lowest cost. Barge transport is more expensive than rail transport at all production rates. Figure 86, appended, gives the total costs associated with this site.

c. Summary of Economic Comparisons of Sites

Figures 87 and 88 plot total annual cost vs. liquid hydrogen plant capacity for the five sites. Figure 87 is for a 5-year contract and Figure 88 is for a 15-year contract. Propellant production costs presented earlier should be added to these costs to determine overall costs for producing and distributing product.

From these graphs it is concluded that Site #3 is the best site located on Government property and Port Canaveral is the best site located off Government property. For a 5-year contract Site #3 is the

TOTAL ANNUAL SITE COSTS DUE TO TRANSPORTATION

COSTS PLUS SITE PREMIUMS

BASIS: All costs in 1970 dollars
5-year Contract

Product Ratio: 1 TPD LH_2:5 TPD LOX:2.5 TPD LIN

Lowest cost transport means has been selected for all cases.

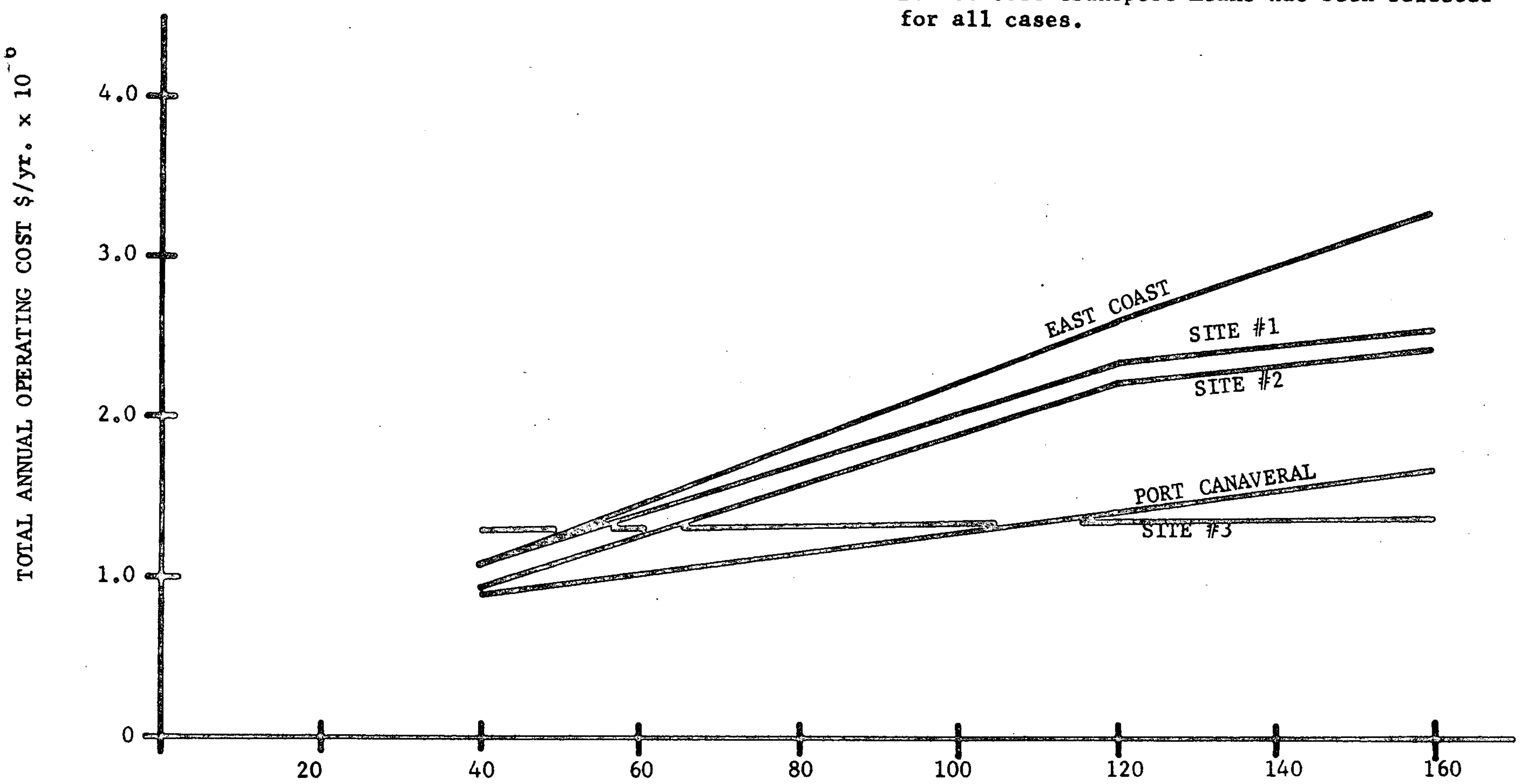


Figure 87

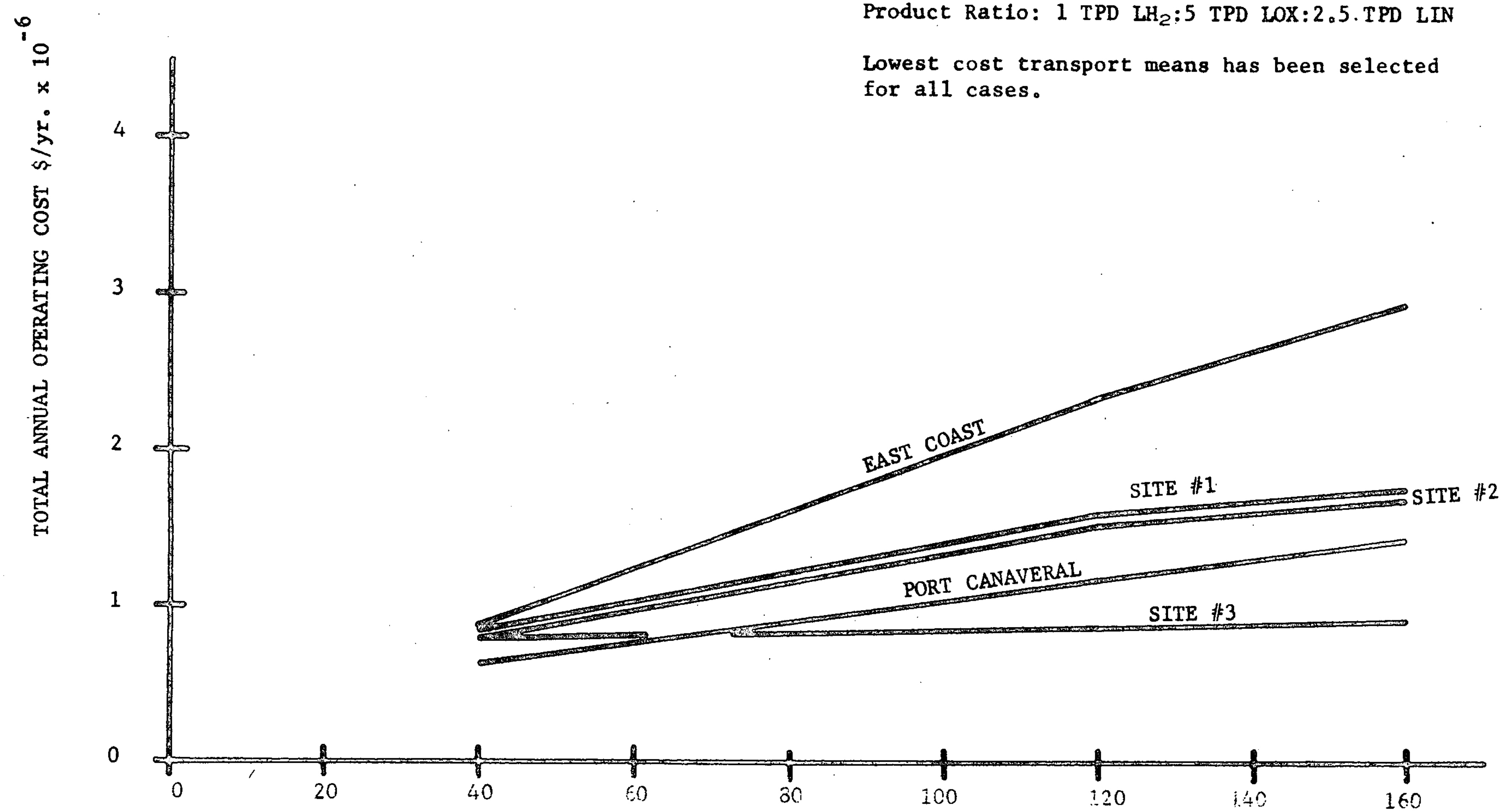
TOTAL ANNUAL SITE COSTS DUE TO TRANSPORTATION

PLUS SITE PREMIUMS

BASIS: All costs in 1970 dollars
15-year contract

Product Ratio: 1 TPD LH_2:5 TPD LOX:2.5 TPD LIN

Lowest cost transport means has been selected for all cases.



LH_2 SHIPPED - TPD

Figure 88

most economical above a production of about 110 TPD LH_2 and Port Canaveral has the lowest cost at lower productions. For a 15-year contract, Site #3 is more economical above 60 TPD and Port Canaveral is attractive at lower productions.

It is further concluded that the choice of either one of these two sites does not significantly affect the cost of liquid hydrogen. If the "close site" is chosen there are legal considerations that need further exploration. These considerations will be discussed in the next section.

d. Legal Considerations

It would appear that, if the Government desires the construction and operation of an integrated propellant manufacturing plant and distribution system to be located on Government-owned land at John F. Kennedy Space Center, then the Government shall plan to have such an integrated, on-site facility constructed entirely at the Government's own risk and expense, with the Government retaining full title to the facility and to the land on which it is built. The facility would be operated on behalf of the Government by a private contractor for an annual fee, to be determined in an appropriate manner, based, in part, at least, on the level of operations and amounts of products produced in such year. The contract or contracts for the operation of the Government-owned, on-site facility would be awarded, after appropriate competition among qualified sources, either on a yearly basis or possibly for periods longer than one (1) year.

In short, if the Government should decide that it is more advantageous to the Government to have an integrated, on-site propellant manufacturing plant and distribution system, then it would appear that a Government-owned Contractor-operator plant (GOCO facility) is the only logical result since it would not seem that any potential contractor would be willing to build such a facility on Government-owned land at the Contractor's risk and expense.

Some of the reasons why contractors would very probably be unwilling to build, own and operate such an integrated propellant manufacturing plant and distribution system, located on Government-owned land, at the Contractor's risk and expense are:

1) Government ownership and control of land created, in effect, a mixed facility.

2) Government ownership and control of land effectively negates the contractor's ownership and control of facility erected at his cost and expense.

3) A long term lease of the plant site by the Government to the Contractor would not cure the above objections since the lease would have to be terminable by the Government within some relatively short period after written notice by the Government.

4) There would undoubtedly be unusual Government-caused hazards to the Contractor's facility and extra hazardous risks placed on the Contractor by reason of the operation of its facility in proximity to the Government's launch and other facilities at John F. Kennedy Space Center. It would appear that insurance costs against these unusual and/or extra hazardous risks may be prohibitive.

5) Under the above conditions the Contractor's right to ship product commercially to customers other than the Government is illusory rather than real.

6) The Contractor's facility would be entirely locked-in by the Government on conclusion or earlier termination of the Government's contract with the supplier.

7) All in all, Government control of (i) the land, (ii) the rights of access thereto, (iii) the conditions under which the contractor would be permitted to operate his plant to produce product, (iv) the safety regulations and standards for such operation and so forth, would make it very unattractive for any contractor to risk the large amount of capital involved on such a facility.

In addition, it is emphasized that costs previously presented are on the basis of private industry ownership. Interfacing with the government in the construction and operation of an integrated propellant production and distribution system would add to these costs and may negate the economic advantages previously indicated.

The Government's interests may be best served by purchasing product from a contractor-owned plant or plants located on off-site land near KSC. This is valid because several such contractor-owned facilities near or relatively near Kennedy Space Center are already in existence. Therefore, NASA is already in a good position to secure maximum competition for the award of propellant contracts. The successful contractor receiving the NASA contract would only have to add to his existing facilities in order to furnish NASA with its propellants requirements which may provide the government with incremental cost benefits.

However it should be duly noted at this point that, since a very sizable capital investment would be required for these large expansions, NASA would have to offer a truly long-term contract, to assure the contractor a guarantee of recovering its investment in such additional facilities plus a reasonable profit. Such provisions permit potential bidders to obtain lower risk and hence, lower cost capital with which to finance the facility, lower interest charges will result in lower product costs to the government.

It would appear that the contracting route selected would determine the most economical procurement method because the provision selected will have more of an economic inpact on the project than the various logistic considerations.

If Government-owned Contractor-operated facilities are selected, the government likely loses the opportunity to participate in any co-commercial opportunities. On the other hand, if appropriate guarantees are not provided to potential bidders, then it will be difficult to generate low cost financing by industry suppliers.

6. Computer Solutions to Projected Load Patterns

The computer program used for NASA Contract NAS8-25147 has been modified to include cost information required for an integrated propellant plant. As stated earlier, the cost of liquid oxygen and liquid nitrogen produced from an integrated facility is kept the same as the cost from a separate facility. Any cost savings that occur in an integrated plant reduce the price of liquid hydrogen. This method of cost accounting permits direct comparison of the program solutions reported in this study with the liquid hydrogen costs reported in NASA Contract NAS8-25147.

The computer calculations are made on the following basis:

1. Only liquid hydrogen costs are presented.
2. Costs are for the East Coast only.
3. Contract life is 5 years.
4. No transport costs from the KSC site to pad 39B are included.
5. Pad storage costs are not included but plant storage costs are included.
6. Transport costs between plants is 64¢/mile.

a. Minimum Requirements Option

The liquid hydrogen requirements for the minimum requirements option are given in Figure 89, appended. The minimum requirements option was investigated in Contract NAS8-25147 with respect to liquid hydrogen plant size, start-up schedule, plant location, and shipping requirements. The report issued at the conclusion of this study determined what the capacity of the liquid hydrogen plant should be, where it should be located, and when it should be built. Liquid hydrogen plants up to 120 TPD were studied in detail. Although plants larger than 120 TPD were outside the scope of the report, they were also briefly considered. In coming to these conclusions, seven possible solutions to the minimum requirements option were studied. The two most attractive solutions are:

Solution III - Ship from APCI plant in Michoud 1970 - 1977, 1981 - 1983;
build 170 TPD plant at KSC in 1978.

Solution IV - Ship from APCI plant in 1970 - 1976, 1978, 1981, 1983; relocate a 30 TPD plant from the West in 1980, build 140 TPD plant in 1979.

The solution numbers are the solution numbers used in NASA Contract NAS8-25147. Figure 90, appended, presents the solutions in detail and gives the computer case numbers that identify computer printouts in NASA Contract NAS8-25147.

This report uses the results of NASA Contract NAS8-25147 (what capacity plant, built where, started when), the integrated propellant plant costs developed in this report, and the new cost of fuel and power to do the following:

1. Compare the 170 TPD plant in Solution III with the 140 TPD plant plus the relocated 30 TPD plant in Solution IV. This comparison is made to show the value of a large integrated plant as opposed to a smaller plant and a relocated plant.

2. Compare an integrated propellant plant with a non-integrated liquid hydrogen plant to show the value of integration.

3. Compare the steam reforming process with the partial oxidation process for generating hydrogen.

4. Compare the three prime mover systems - electric motors, steam turbines, and gas turbines, based on the expected power and fuel costs for the total program life.

5. Determine the effect of escalation on the total program cost.

The above comparisons have been made earlier in this report for constant liquid hydrogen production. The value of the computer comparisons is that they are based on projected actual liquid hydrogen requirements and show the effect of variable demand on total program cost.

Figure 91, appended, summarizes all the computer cases run for the two solutions. The case numbers given in this figure refer to the computer printouts given in Appendix B.

1) Comparison of Solution III with Solution IV

Inspection of Cases 5 and 50 reveals that Solution III is the most economical for the minimum requirements option. This indicates that the marginal value of an additional 30 TPD from an integrated facility is greater than a relocated 30 TPD plant.

2) Comparison of an Integrated Propellant Plant with a Liquid Hydrogen Plant

Comparison of Case 5 with Case 22 shows that the integrated propellant plant produces liquid hydrogen for 25.8¢/lb., 0.7¢/lb. less than the stand alone liquid hydrogen plant.

3) Comparison of Steam Reforming Process with Partial Oxidation Process

Comparison of Case 20 with Case 26 shows that the steam reforming process produces liquid hydrogen for 0.58¢/lb. less than the partial oxidation process even though the feedstock for the partial oxidation process is 10¢/10^6 Btu less expensive.

4) Prime Mover Evaluation

Conclusions about the prime mover system can be drawn by comparing Cases 5, 7, 20 and 24.

Case	Driver	Liquid Hydrogen Cost ¢/LB
5	Motor - 6 mil	25.80
7	Motor - 5 mil	25.21
20	Gas Turbine	25.07
24	Steam Turbine	25.26

It is seen that with the fuel costs used (45¢/10^6 Btu for oil, 55¢/10^6 Btu for naptha) the gas turbine drive produces liquid hydrogen most economically. However, the electric drive system with 5 mil power is also attractive.

5) Escalation

Cases 8 and 21 are included to illustrate the effect of 5% per year escalation on the total program cost for the electric drive (Case 7) and the gas turbine drive (Case 20).

6) Summary of Cases and Conclusions

The computer results show that the lowest cost solution to the minimum requirements option is a 170 TPD integrated propellant plant built at KSC in 1978. This integrated propellant plant should employ the steam reforming process and use naptha as feed. The prime mover system should be either gas turbine using fuel oil or electric drive, depending on the actual costs of energy when the plant is built.

b. 50 Launch Option

The 50 launch option represents a requirements option in which the testing requirements are 1/2 of the minimum requirements option. The launch schedule starts at three per year in 1977 and builds up to 50 per year in 1981. The liquid hydrogen requirements for this option are given in Figure 92, appended.

The two most attractive solutions for this option are:

1) Relocate the 60 TPD LH_2 plant from Sacramento to KSC in 1980, run the 30 TPD LH_2 APCI at Michoud 1970 - 1980 and ship from the West Coast from 1981 - 1985.

2) Build a 60 TPD integrated propellant plant in 1980, run APCI at Michoud from 1970 - 1980 and ship from the West Coast from 1981 - 1985.

Figure 93, appended, gives the program cost for these two solutions. The best solution is to relocate the 60 TPD West Coast plant. The liquid hydrogen price reduction,due to integration,is not enough to give the integrated facility a cost advantage over a fully depreciated plant. Case 70 in Figure 93 gives the total program cost if 5% per year escalation is added to Case 70. The computer printouts for this option are given in Appendix C.

c. Revised Minimum Requirements Option

The minimum requirements option was revised September 8, 1970. The liquid hydrogen requirements for the revised minimum requirements option are presented in Figure 94, appended. The liquid hydrogen requirements for the Lewis Research Center are added in with the MSFC demand.

The solutions investigated for this option are summarized in Figure 95, appended. The case numbers shown identify the computer printouts in Appendix D.

1. Late Relocation of 60 TPD Sacramento Hydrogen Plant (LSH)

In Case 81, the 60 TPD plant in Sacramento is relocated at Cape Kennedy in 1981. Liquid hydrogen for the test program at KSC and MTF is supplied from the APCI plant at Michoud and the West Coast, if required. Comparison of this case with others illustrates that premiums in transportation charges during peaks are greater than savings in deferring investment by waiting until after the testing to relocate LSH at KSC.

2. Early Relocation of LSH

Case 85 was run to show total program costs if LSH was relocated at KSC at the earliest possible date (1973). LSH is capable of supplying most of the hydrogen for the test program and for the space shuttle.

Requirements of over 60 TPD are met from the APCI plant at Michoud.

3. Relocation of LSH in Time for the Test Program

Case 83 gives the total program cost for relocating the LSH plant at KSC in time to meet the requirements of the test program starting with the fourth quarter of 1975. Hydrogen requirements in excess of 60 TPD are met by shipping from the APCI plant at Michoud. This solution provides the lowest program cost of all the cases considered. Case 84 shows the effect of an escalation of 5% per year on liquid hydrogen costs for the entire program.

4. 60 TPD Integrated Propellant Plant

Case 86 is the same as Case 83 except that a 60 TPD integrated propellant plant is constructed to start in the fourth quarter of 1975 rather than relocate LSH. The costs for this solution are somewhat higher than the costs for relocating Sacramento.

5. 90 TPD Integrated Propellant Plant

Case 88 was included to illustrate the effect of eliminating all shipping from the APCI plant at Michoud. A 90 TPD integrated propellant plant is built at KSC in the fourth quarter of 1975. Liquid hydrogen is shipped from the APCI plant until the fourth quarter of 1975, and then the 90 TPD integrated propellant plant supplies the East Coast. The high program costs for the solution indicate that it is advantageous to keep the APCI plant running.

6. Conclusions

The most economical means of supplying liquid hydrogen for the revised minimum requirements option is to move the 60 TPD LSH plant to KSC for production beginning the fourth quarter of 1975.

APPENDIX A

FIGURES

Figure 5

TABULATED SUMMARY OF PROPELLANT PRODUCTION FACILITIES INVESTMENT

Basis: All Costs on Basis of 1970 Dollars

NON-INTEGRATED PLANTS

AIR SEPARATION & LIQUEFACTION
800 TPD LOX, 400 TPD LIN & 120 TPD GN_2

Plant	Prime Mover	Investment
Air Separation	Electric Motors	\$5,800,000
Air Separation & Liquefier	Electric Motors	8,300,000
Air Separation & Liquefier	Steam Turbines	9,200,000
Air Separation & Liquefier	Gas and Steam Turbines	9,700,000

LIQUID HYDROGEN PLANTS
160 TPD LH_2 & 10 TPD GH_2

Hydrogen Generation System	Prime Mover	Process Feed	Investment
Steam Reformer	Electric Motors	Natural Gas	\$33,600,000
Steam Reformer	Electric Motors	Naptha	34,300,000
Steam Reformer	Steam Turbines	Natural Gas	34,720,000
Steam Reformer	Steam Turbines	Naptha	35,440,000
Steam Reformer	Gas and Steam Turbines	Natural Gas	36,120,000
Steam Reformer	Gas and Steam Turbines	Naptha	36,860,000
Partial Oxidation	Electric Motors	Naptha	40,720,000
Partial Oxidation	Electric Motors	Fuel or Crude Oil	41,780,000
Partial Oxidation	Steam Turbines	Naptha	42,420,000
Partial Oxidation	Steam Turbines	Fuel or Crude Oil	43,460,000
Partial Oxidation	Gas and Steam Turbines	Naptha	43,780,000
Partial Oxidation	Gas and Steam Turbines	Fuel or Crude Oil	44,700,000

INTEGRATED PRODUCTION PLANTS
160 TPD LH_2, 10 TPD GH_2, 800 TPD LOX, 400 TPD LIN & 120 TPD GN_2

Hydrogen Generation System	Prime Mover	Process Feed	Investment
Steam Reformer	Electric Motors	Natural Gas	\$39,260,000
Steam Reformer	Electric Motors	Naptha	39,980,000
Steam Reformer	Steam Turbine	Natural Gas	41,040,000
Steam Reformer	Steam Turbine	Naptha	41,780,000
Steam Reformer	Gas and Steam Turbine	Natural Gas	42,350,000
Steam Reformer	Gas & Steam Turbine	Naptha	43,080,000
Partial Oxidation	Electric Motors	Naptha	43,640,000
Partial Oxidation	Electric Motors	Fuel or Crude Oil	44,790,000
Partial Oxidation	Steam Turbines	Naptha	45,850,000
Partial Oxidation	Steam Turbines	Fuel or Crude Oil	47,000,000
Partial Oxidation	Gas and Steam Turbines	Naptha	47,160,000
Partial Oxidation	Gas and Steam Turbines	Fuel or Crude Oil	48,220,000

Figure 6
AIR SEPARATION PLANT INVESTMENT
ELECTRIC DRIVE
LOX/LIN RATIO = 2.0

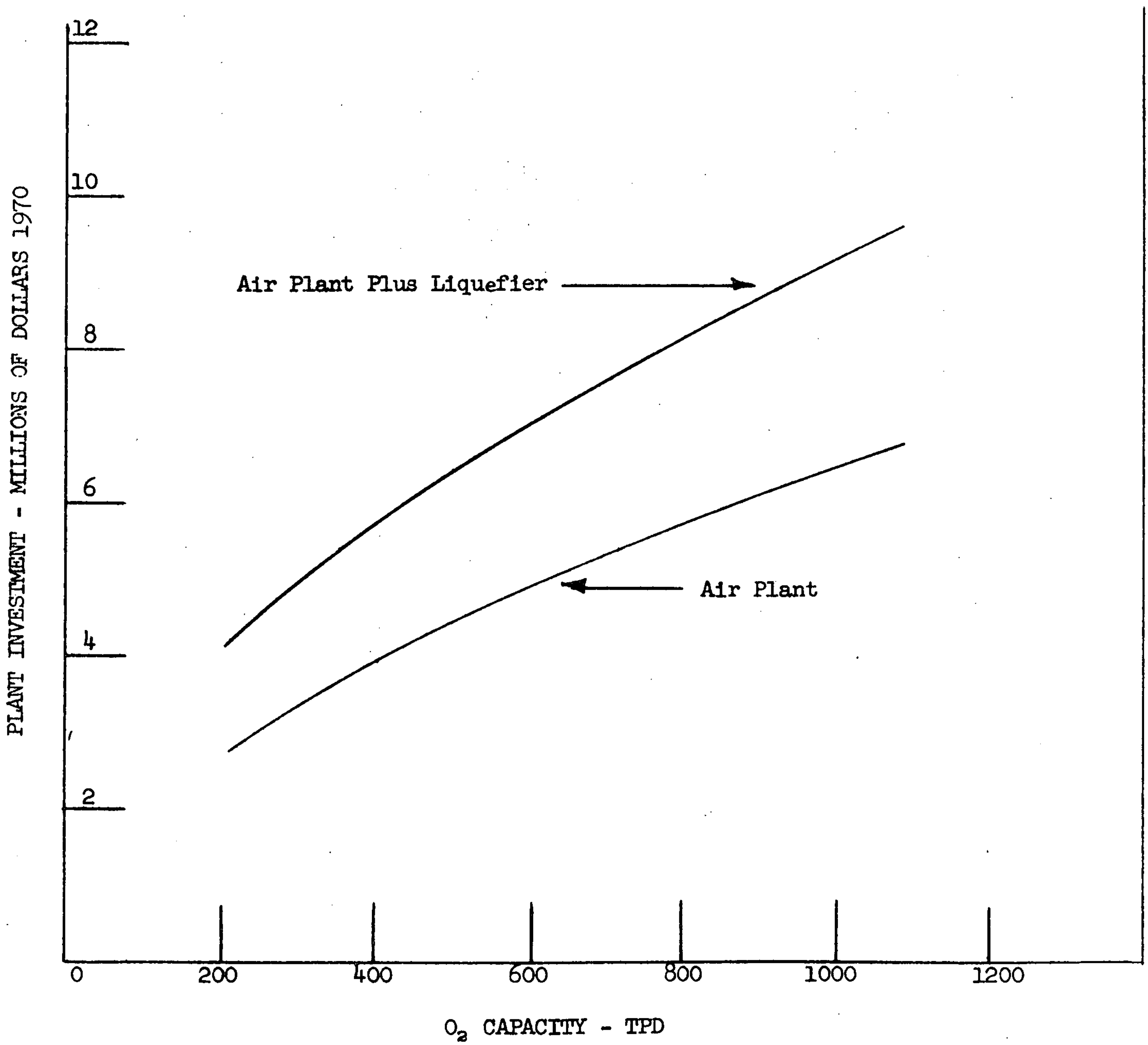


Figure 7
AIR SEPARATION PLANT PLUS
LIQUEFIER INVESTMENT
GAS TURBINE DRIVE
LOX/LIN RATIO = 2.0

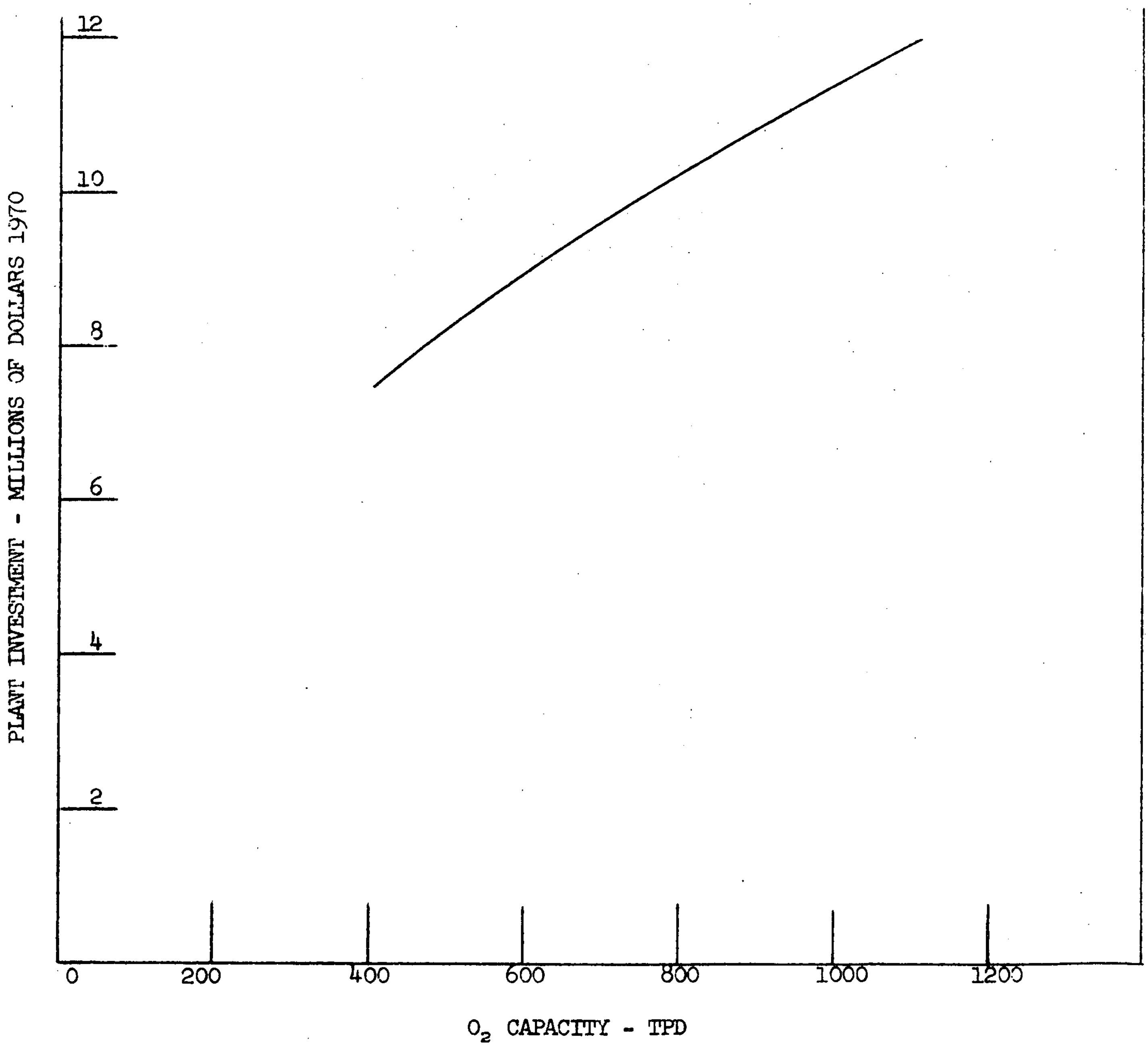


Figure 8

AIR SEPARATION PLANT
PLUS LIQUEFIER INVESTMENT
STEAM TURBINE DRIVE
LOX/LIN RATIO = 2.0

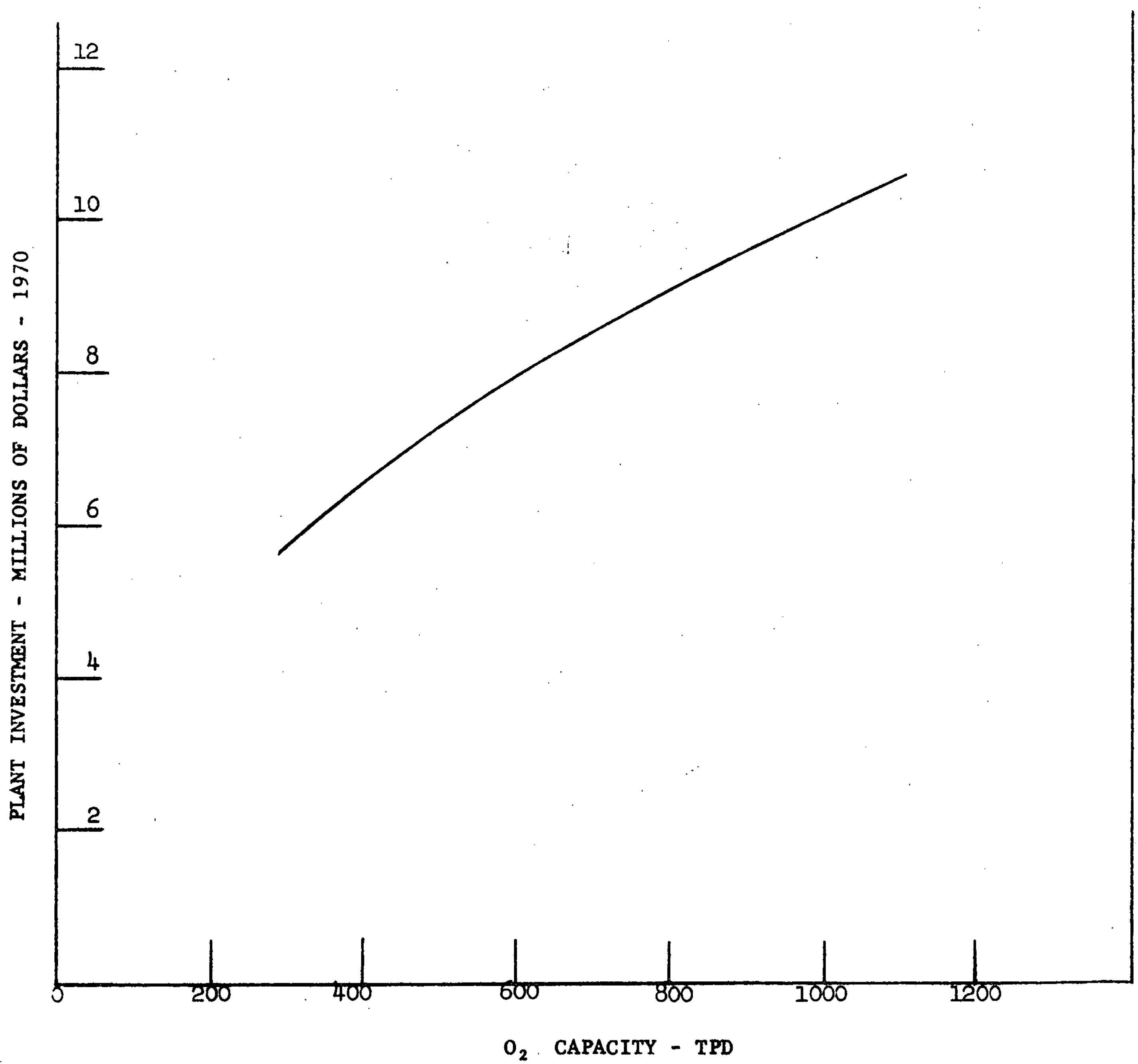


Figure 9
LIQUID HYDROGEN PLANT COSTS
STEAM REFORMER H_2 GENERATION
ALL ELECTRIC DRIVE

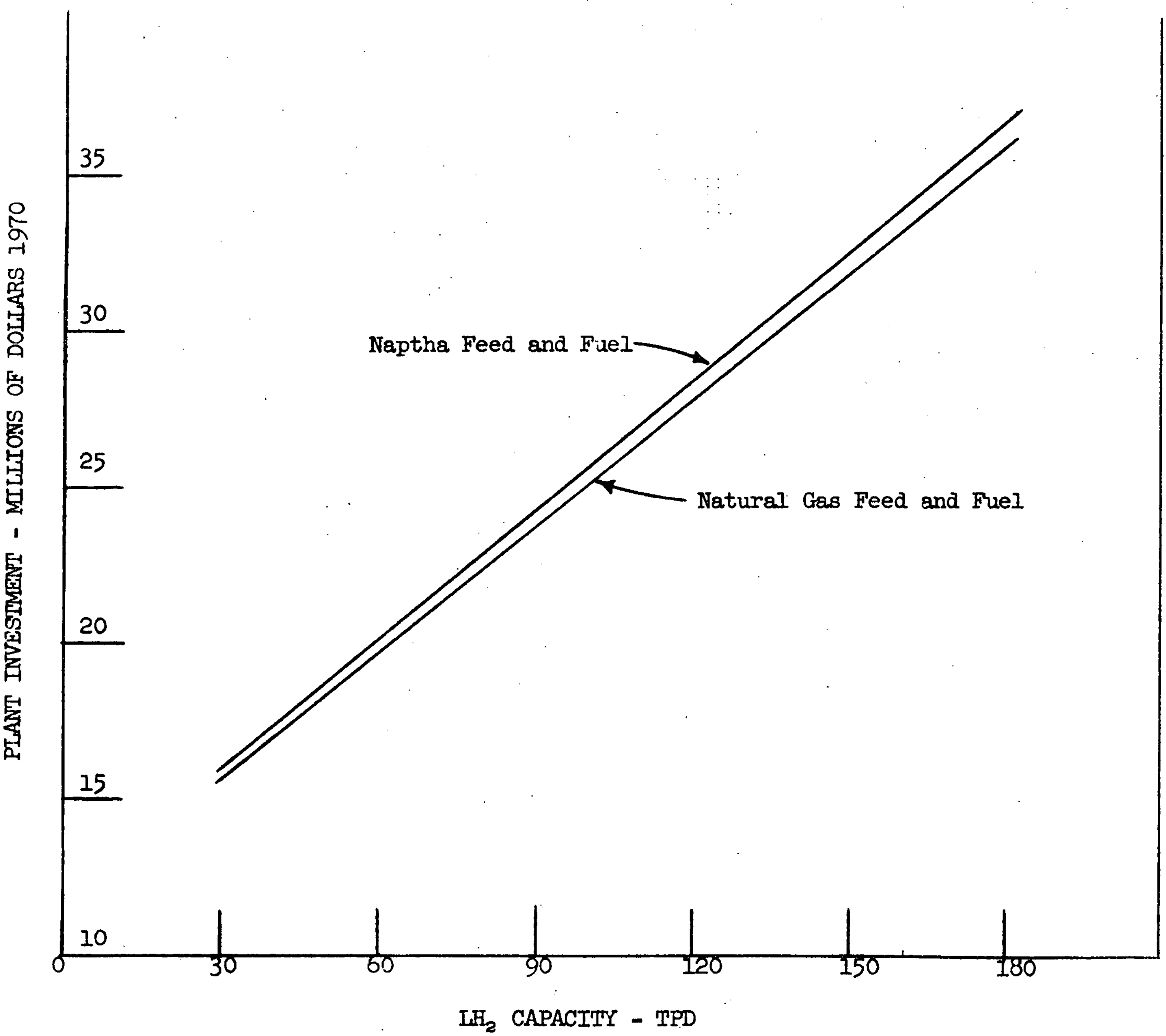


Figure 10
LIQUID HYDROGEN PLANT COSTS
STEAM REFORMER H_2 GENERATION
GAS TURBINE DRIVE-RECYCLE N_2 COMPRESSOR
STEAM DRIVEN CENTRIFUGAL COMPRESSORS
ELECTRIC DRIVE LH_2 RECYCLE COMPRESSORS

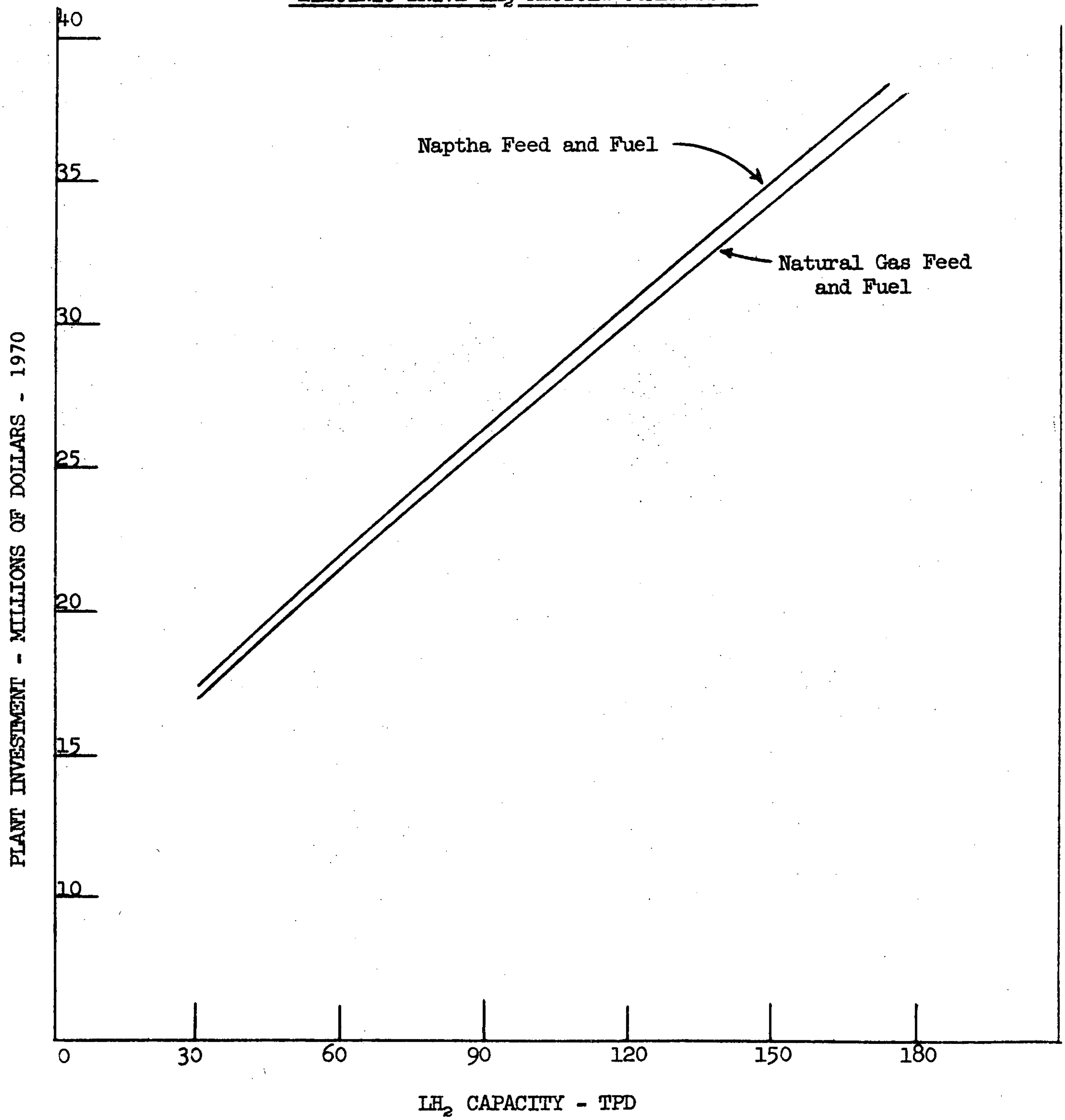


Figure 11
LIQUID HYDROGEN PLANT COSTS
STEAM REFORMER H_2 GENERATION
STEAM DRIVEN CENTRIFUGAL COMPRESSORS
ELECTRIC DRIVE LH_2 RECYCLE COMPRESSORS

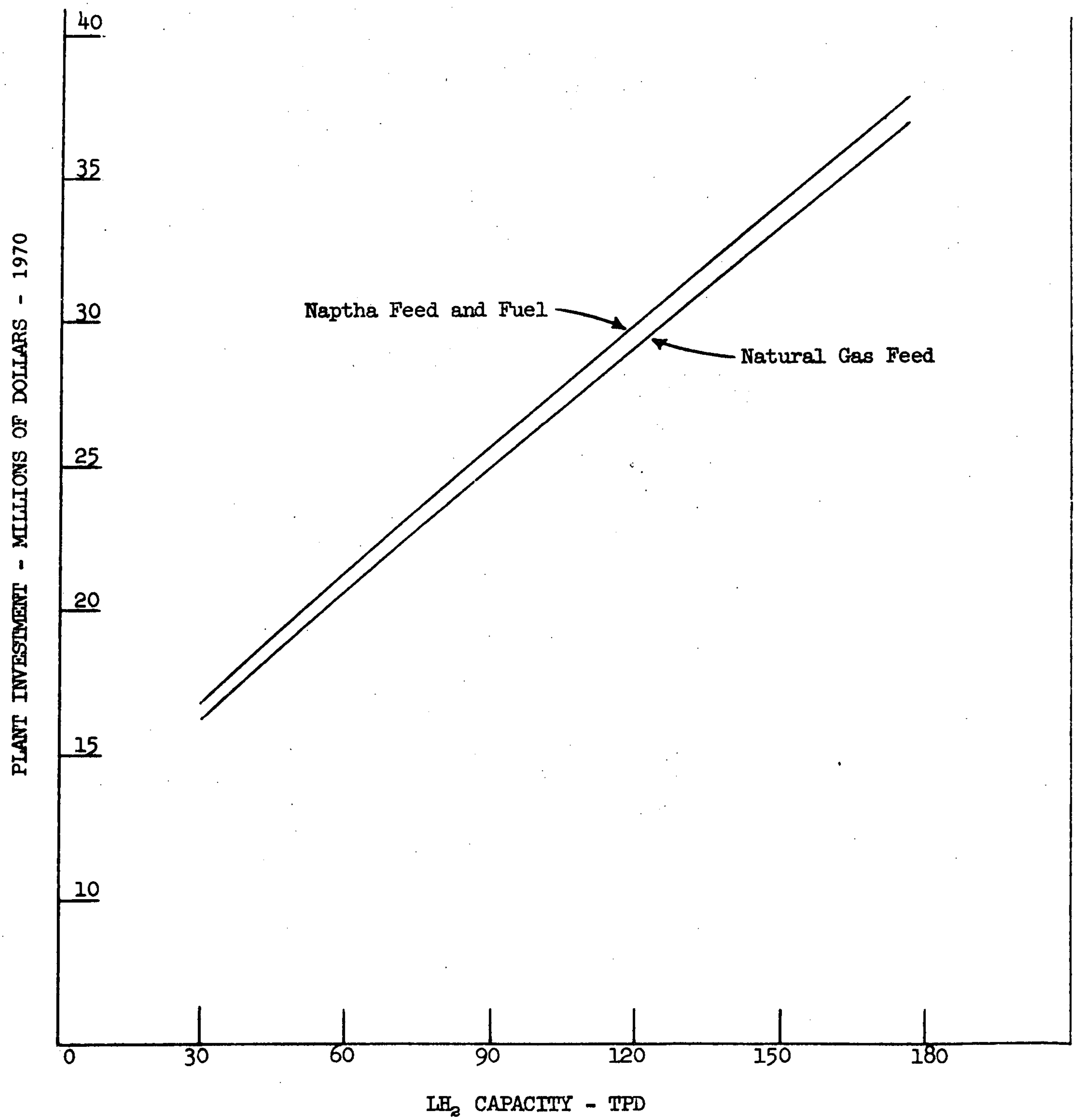


Figure 12

LIQUID HYDROGEN PLANT INVESTMENT
PARTIAL OXIDATION H_2 GENERATION
ALL ELECTRIC DRIVE

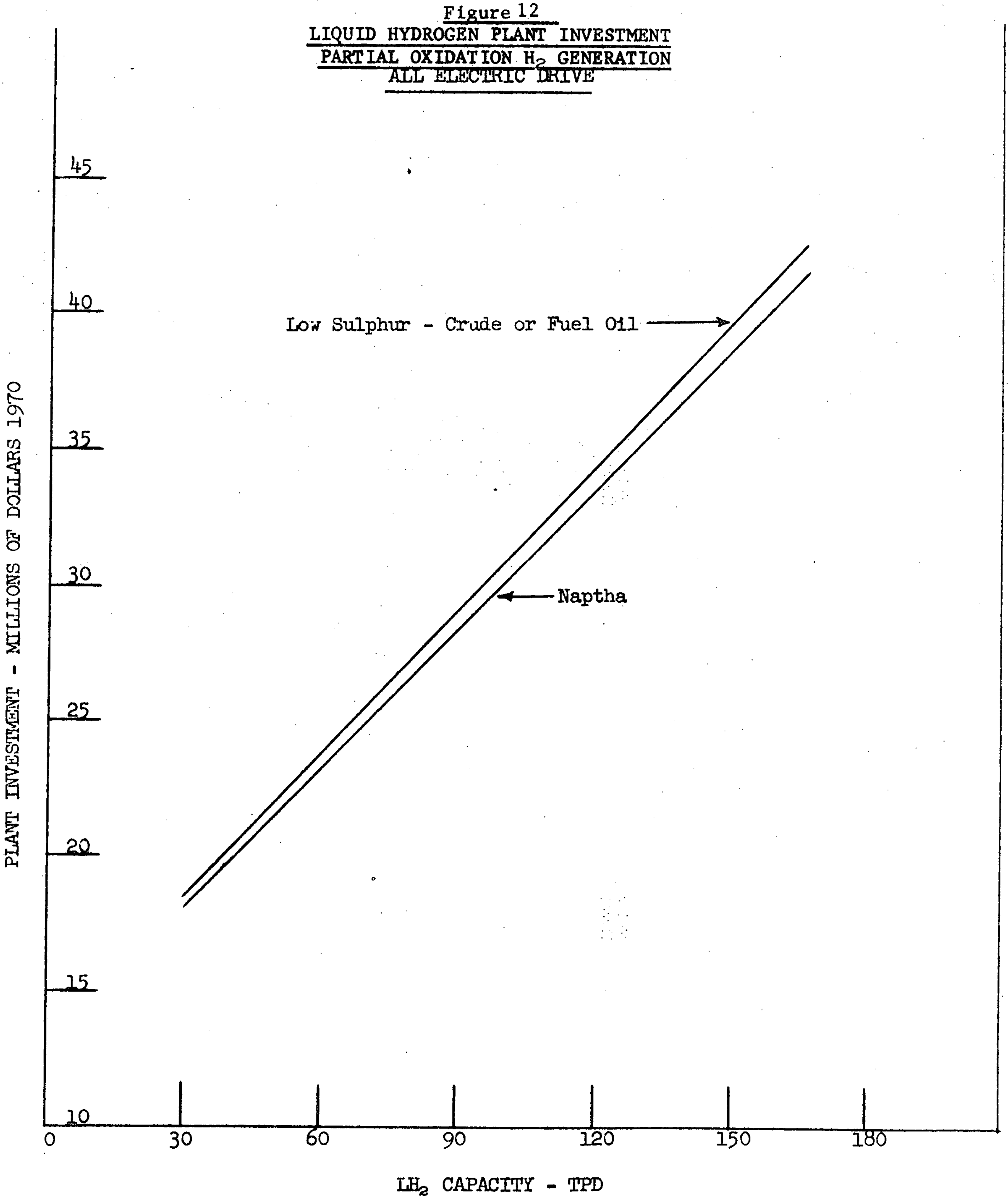


Figure 13

LIQUID HYDROGEN PLANT INVESTMENT
PARTIAL OXIDATION H_2 GENERATION
GAS TURBINE DRIVE N_2 RECYCLE COMPRESSOR
STEAM DRIVEN CENTRIFUGAL COMPRESSORS
ELECTRIC DRIVE LH_2 RECYCLE COMPRESSORS

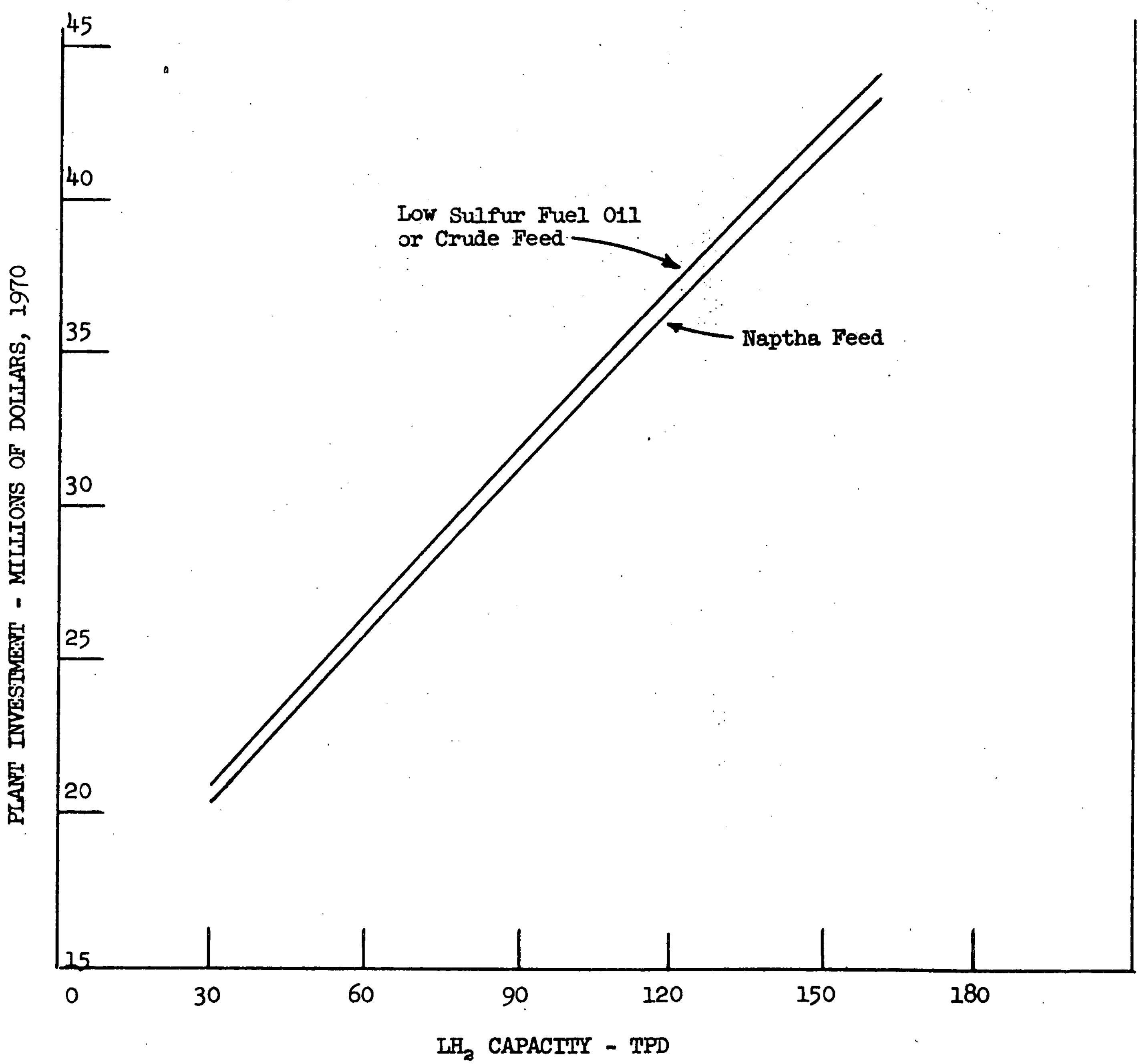


Figure 14

LIQUID HYDROGEN PLANT INVESTMENT
PARTIAL OXIDATION H_2 GENERATION
STEAM DRIVE CENTRIFUGAL COMPRESSORS
ELECTRIC LH_2 RECYCLE COMPRESSORS

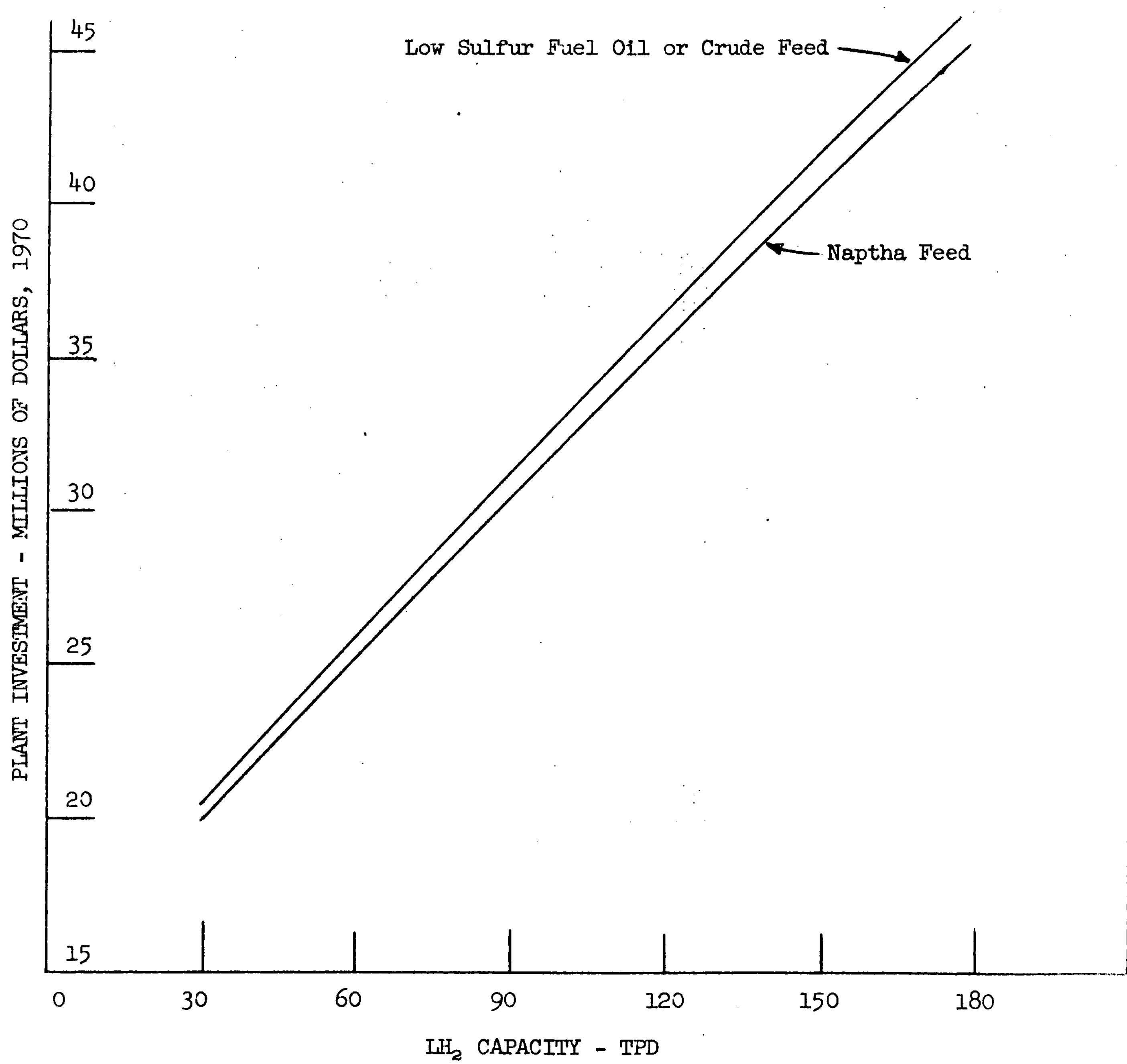


Figure 15

INTEGRATED PROPELLANT PRODUCTION PLANT INVESTMENT
STEAM REFORMER H_2 GENERATION
ELECTRIC DRIVE COMPRESSION EQUIPMENT

PRODUCT RATIO = 1 TPD LH_2 : 5 TPD LOX : 2.5 TPD LIN

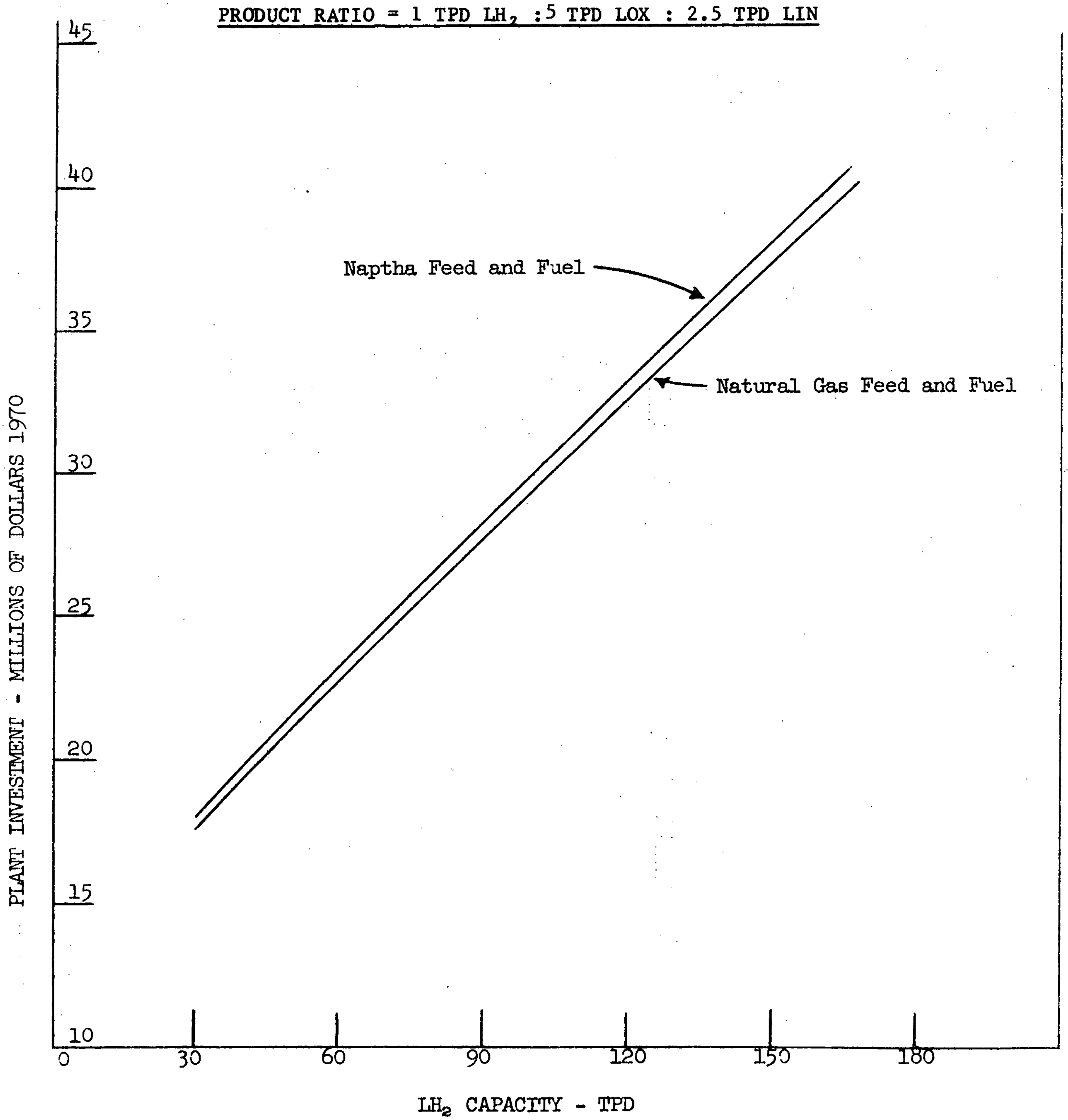


Figure 16

INTEGRATED PROPELLANT PRODUCTION PLANT INVESTMENT
STEAM REFORMER H_2 GENERATION
GAS TURBINE DRIVE AIR AND N_2 RECYCLE COMPRESSORS
OTHER CENTRIFUGAL COMPRESSORS STEAM DRIVEN
ELECTRIC DRIVE LH_2 RECYCLE COMPRESSORS

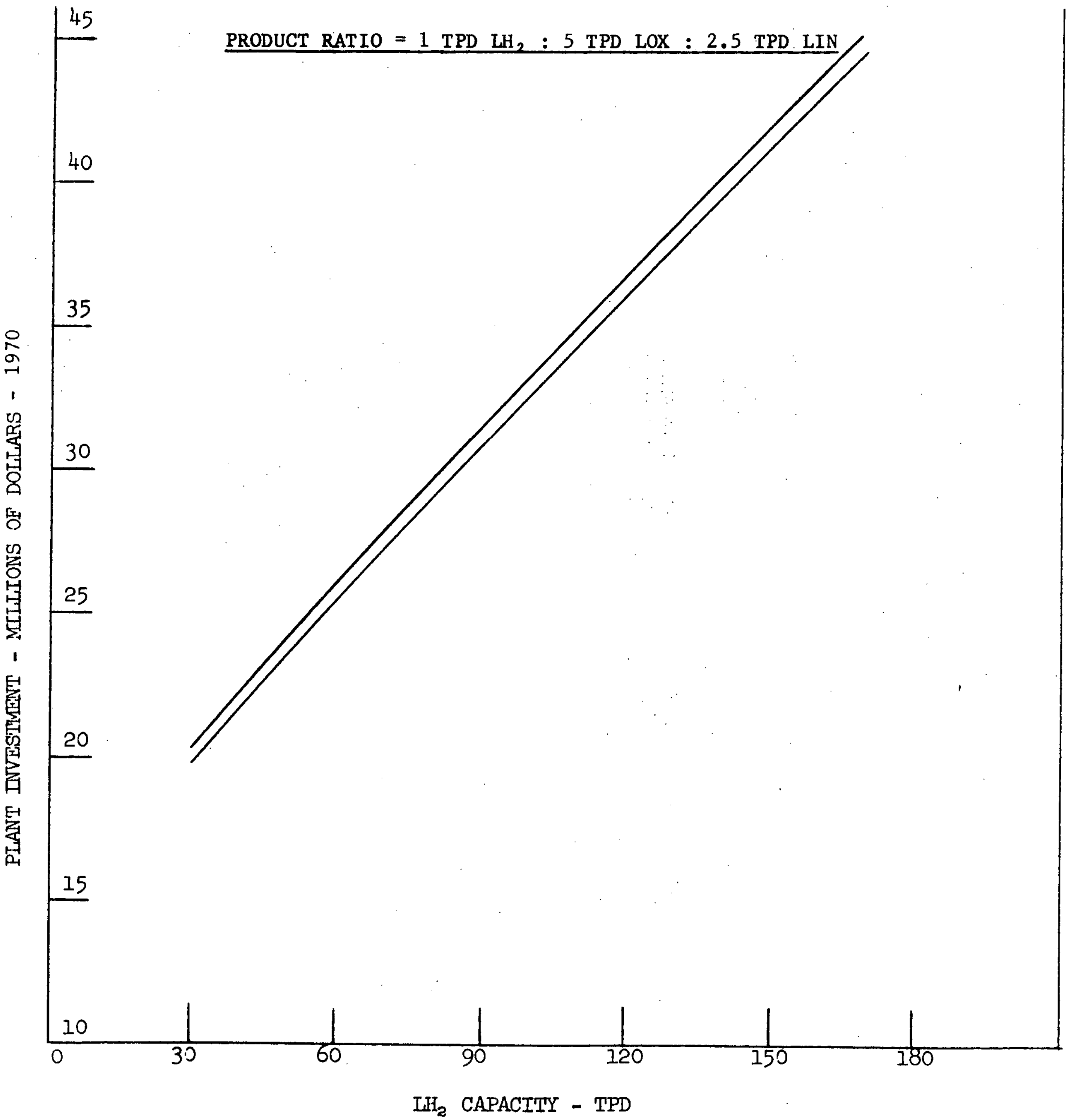


Figure 17

INTEGRATED PROPELLANT PRODUCTION PLANT INVESTMENT
STEAM REFORMER H_2 GENERATION
STEAM DRIVE CENTRIFUGAL COMPRESSORS
ELECTRIC DRIVE LH_2 RECYCLE COMPRESSORS

PRODUCT RATIO = 1 TPD LH_2 : 5 TPD LOX : 2.5 TPD LIN

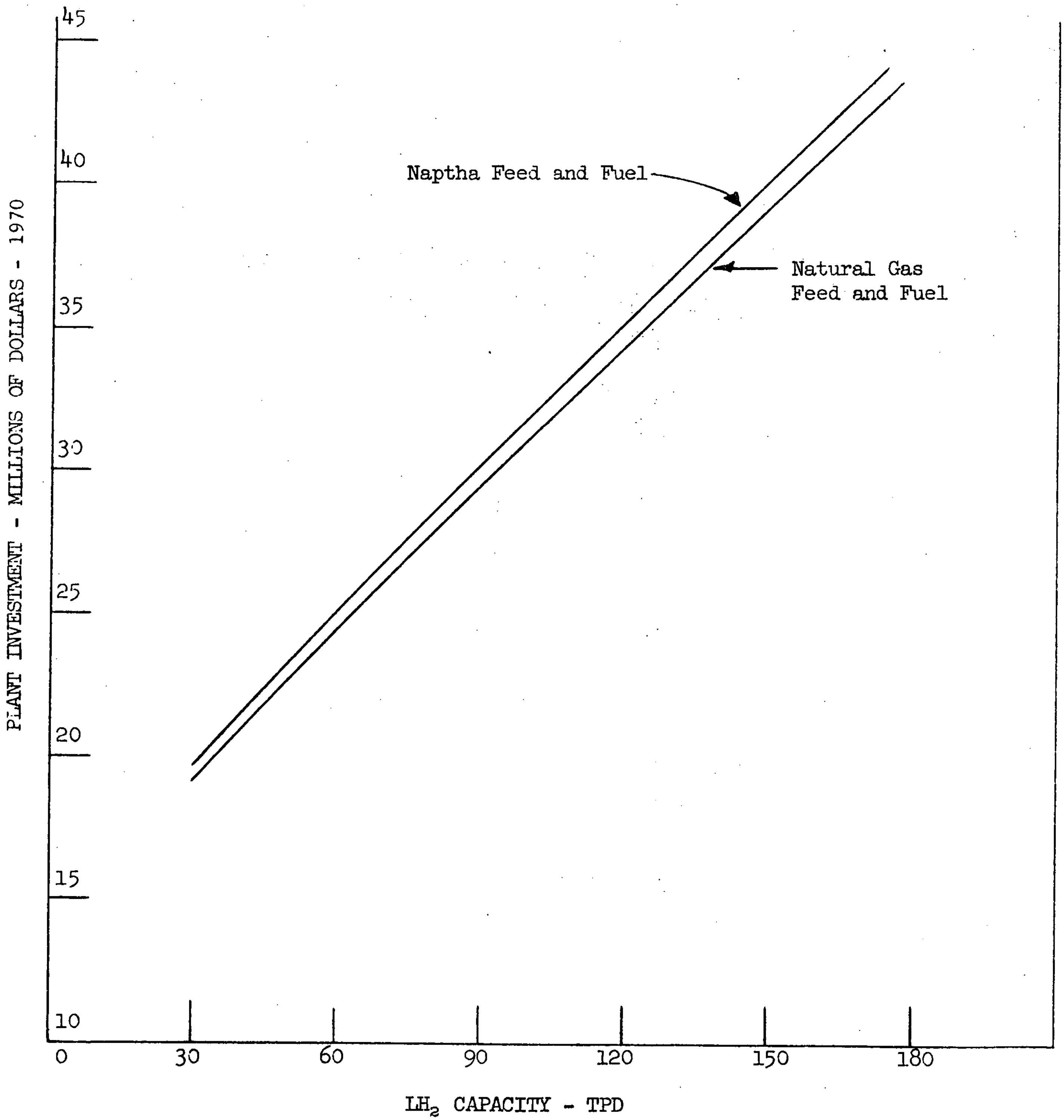


Figure 18

INTEGRATED PROPELLANT PRODUCTION PLANT INVESTMENT
PARTIAL OXIDATION H_2 GENERATION
ALL ELECTRIC DRIVE

PRODUCT RATIO = 1 TPD LH_2 : 5 TPD LOX : 2.5 TPD LIN

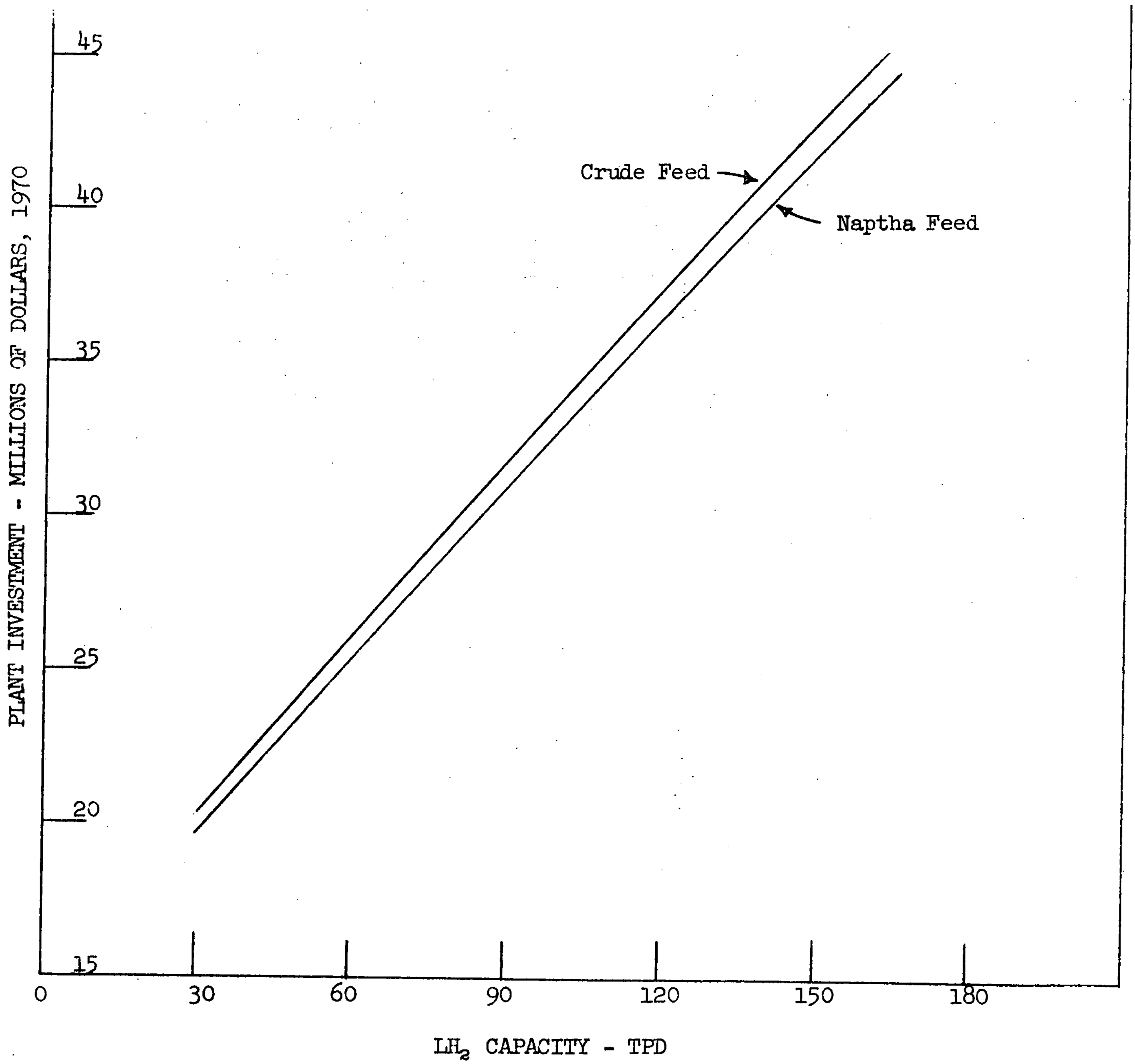


Figure 19

INTEGRATED PROPELLANT PRODUCTION PLANT INVESTMENT
PARTIAL OXIDATION H_2 GENERATION
GAS TURBINE DRIVE AIR AND N_2 RECYCLE COMPRESSORS
OTHER CENTRIFUGAL COMPRESSORS STEAM DRIVEN
ELECTRIC DRIVEN LH_2 RECYCLE COMPRESSORS

PRODUCT RATIO = 1 TPD LH_2 : 5 TPD LOX : 2.5 TPD LIN

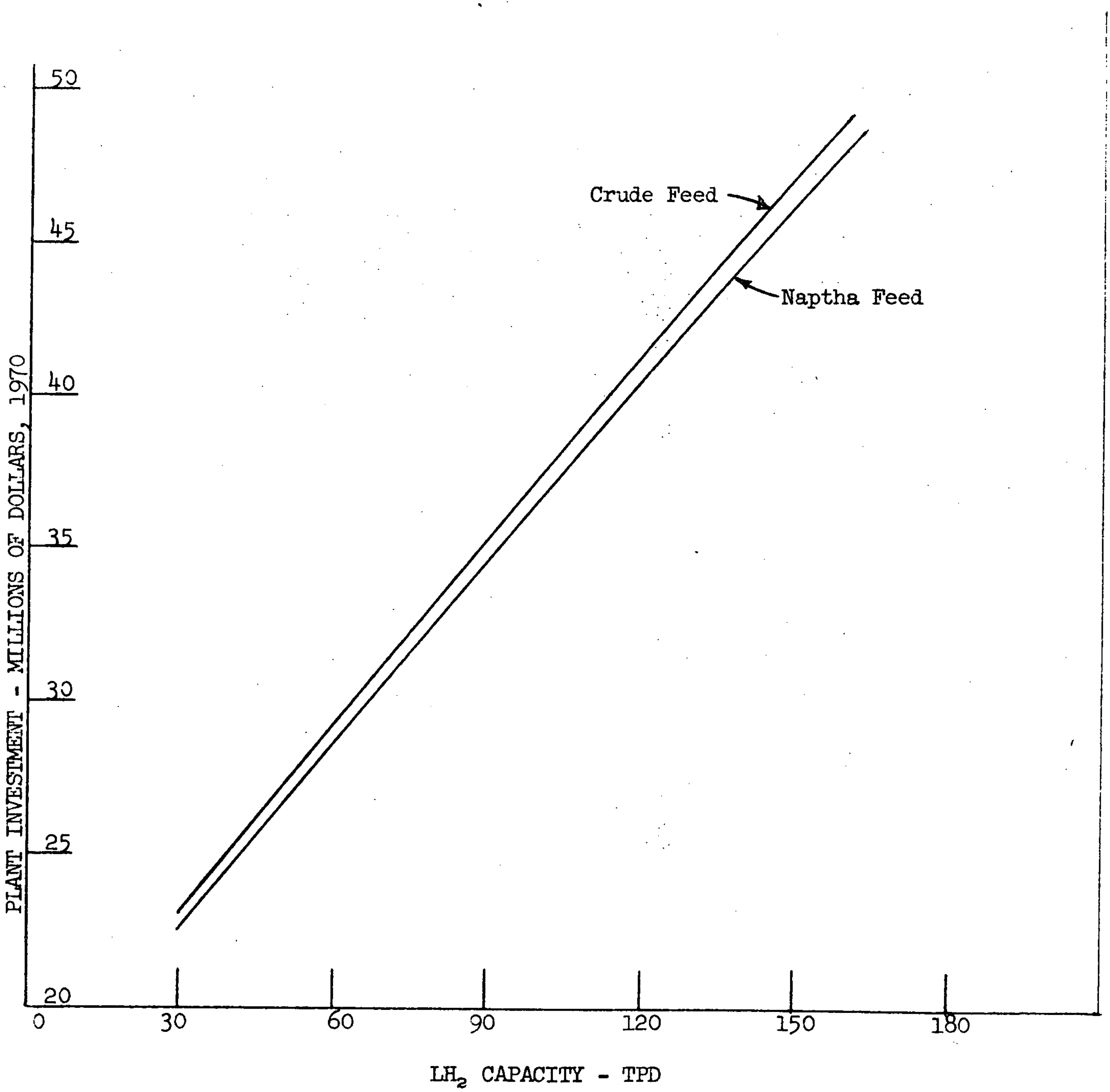


Figure 20

INTEGRATED PROPELLANT PRODUCTION PLANT INVESTMENT
PARTIAL OXIDATION H_2 GENERATION
STEAM DRIVEN CENTRIFUGAL COMPRESSORS
ELECTRIC DRIVEN LH_2 RECYCLE COMPRESSORS

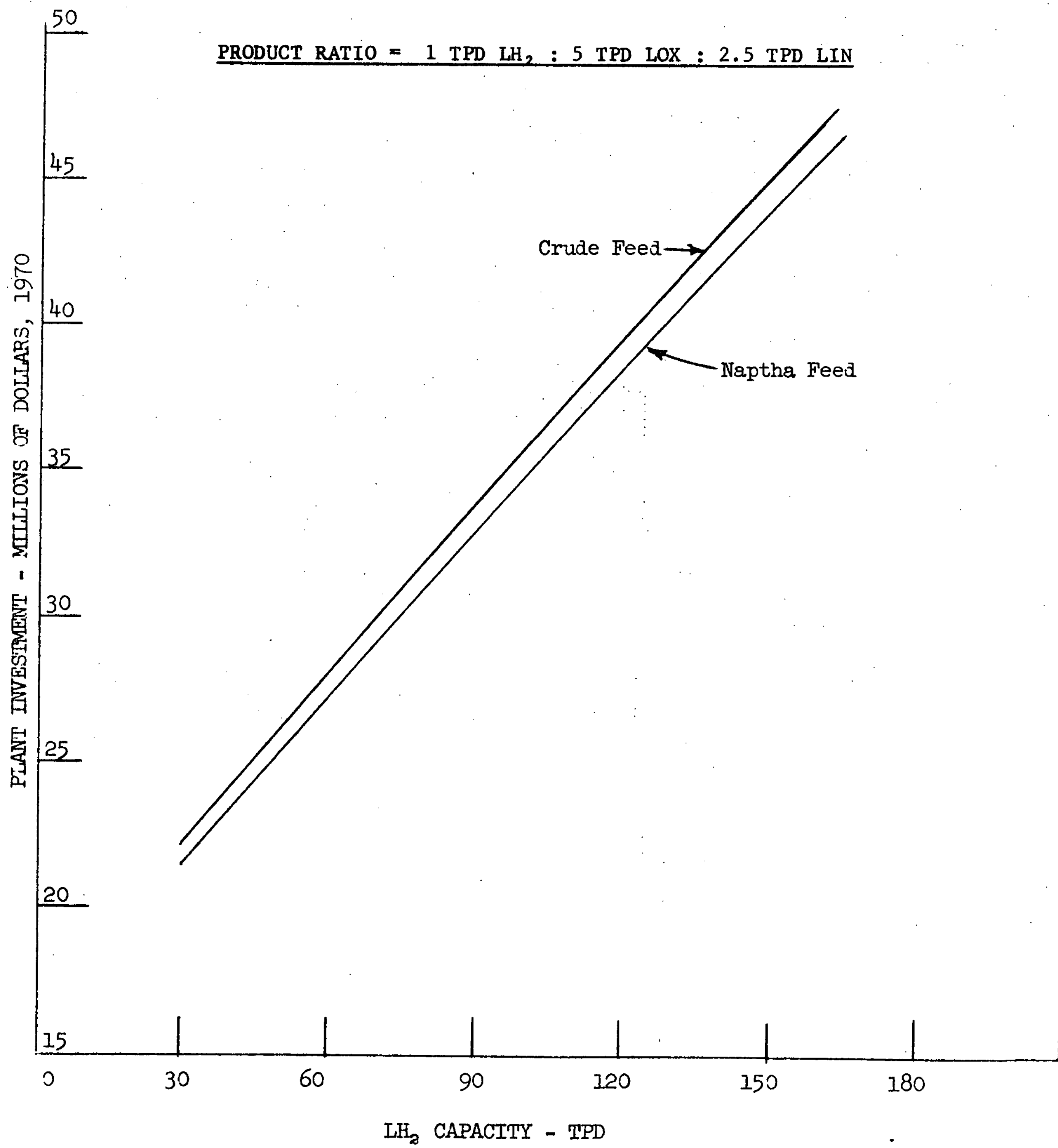


Figure 21

TABULATED SUMMARY OF PROPELLANT PRODUCTION FACILITIES UTILITY REQUIREMENTS

NON-INTEGRATED PLANTS

AIR SEPARATION & LIQUEFACTION
800 TPD LOX, 400 TPD LIN & 120 TPD GN_2

Plant	Prime Mover	Utility Requirements Electricity-KW	Utility Requirements Fuel-Btu/Hr.x10^{-6}
Air Separation	Electric Motors	10,200	-
Air Separation & Liquefaction	Electric Motors	28,800	-
Air Separation & Liquefaction	Steam Turbines	-	395
Air Separation & Liquefaction	Gas & Steam Turbines	-	318

LIQUID HYDROGEN PLANTS
160 TPD LH_2 & 10 TPD GH_2

Hydrogen Generation System	Prime Mover	Process Feed	Utility Requirements Electricity-KW	Utility Requirements Fuel-Btu/Hr.x10^{-6}
Steam Reformer	Electric Motors	Natural Gas	83,100	1,140
Steam Reformer	Electric Motors	Naptha	83,100	1,250
Steam Reformer	Steam Turbines	Natural Gas	50,200	1,510
Steam Reformer	Steam Turbines	Naptha	50,200	1,630
Steam Reformer	Gas & Steam Turbines	Natural Gas	50,200	1,480
Steam Reformer	Gas & Steam Turbines	Natural Gas	50,200	1,600
Partial Oxidation	Electric Motors	Naptha	93,900	1,200
Partial Oxidation	Electric Motors	Fuel & Crude Oil	93,900	1,200
Partial Oxidation	Steam Turbines	Naptha	50,200	1,720
Partial Oxidation	Steam Turbines	Fuel & Crude Oil	50,200	1,720
Partial Oxidation	Gas & Steam Turbines	Naptha	50,200	1,620
Partial Oxidation	Gas & Steam Turbines	Fuel & Crude Oil	50,200	1,620

INTEGRATED PRODUCTION PLANTS
160 TPD LH_2, 10 TPD GH_2, 800 TPD LOX, 400 TPD LIN, 120 TPD GN_2

Hydrogen Generation System	Prime Mover	Process Feed	Utility Requirements Electricity-KW	Utility Requirements Fuel-Btu/Hr.x10^{-6}
Steam Reformer	Electric Motors	Natural Gas	110,800	1,140
Steam Reformer	Electric Motors	Naptha	110,800	1,250
Steam Reformer	Steam Turbines	Natural Gas	50,200	1,830
Steam Reformer	Steam Turbines	Naptha	50,200	1,940
Steam Reformer	Gas & Steam Turbines	Natural Gas	50,200	1,665
Steam Reformer	Gas & Steam Turbines	Naptha	50,200	1,785
Partial Oxidation	Electric Motors	Naptha	119,500	1,200
Partial Oxidation	Electric Motors	Fuel & Crude Oil	119,500	1,200
Partial Oxidation	Steam Turbines	Naptha	50,200	2,000
Partial Oxidation	Steam Turbines	Fuel & Crude Oil	50,200	2,000
Partial Oxidation	Gas & Steam Turbines	Naptha	50,200	1,810
Partial Oxidation	Gas & Steam Turbines	Fuel & Crude Oil	50,200	1,810

Figure 22

AIR SEPARATION PLANT AND LIQUEFIER

POWER REQUIREMENTS

ELECTRIC DRIVE

LOX/LIN RATIO = 2.0

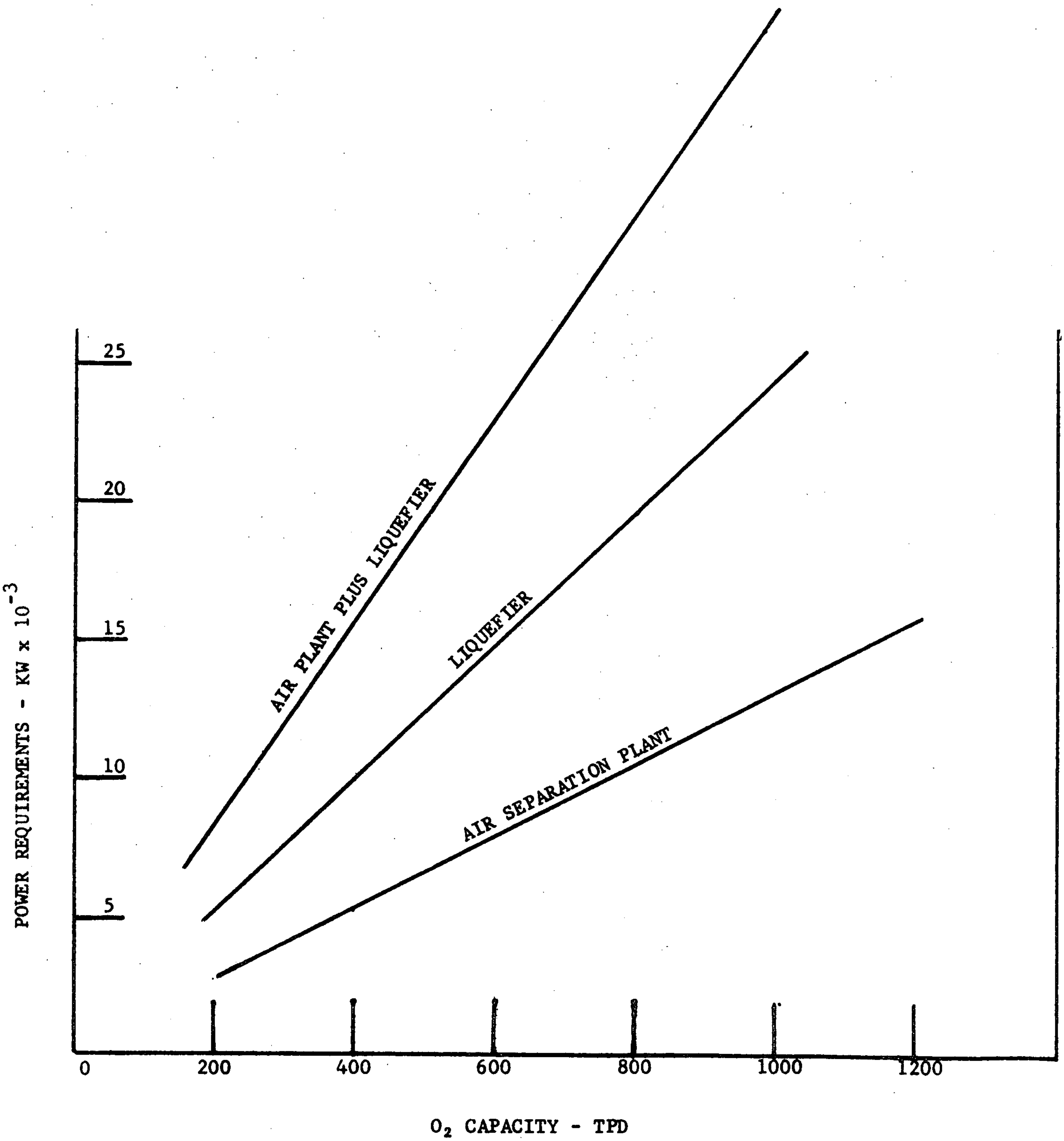


Figure 23

ENERGY REQUIREMENTS FOR
GAS TURBINE DRIVEN AIR PLANT PLUS LIQUEFIER
LOX/LIN RATIO = 2.0

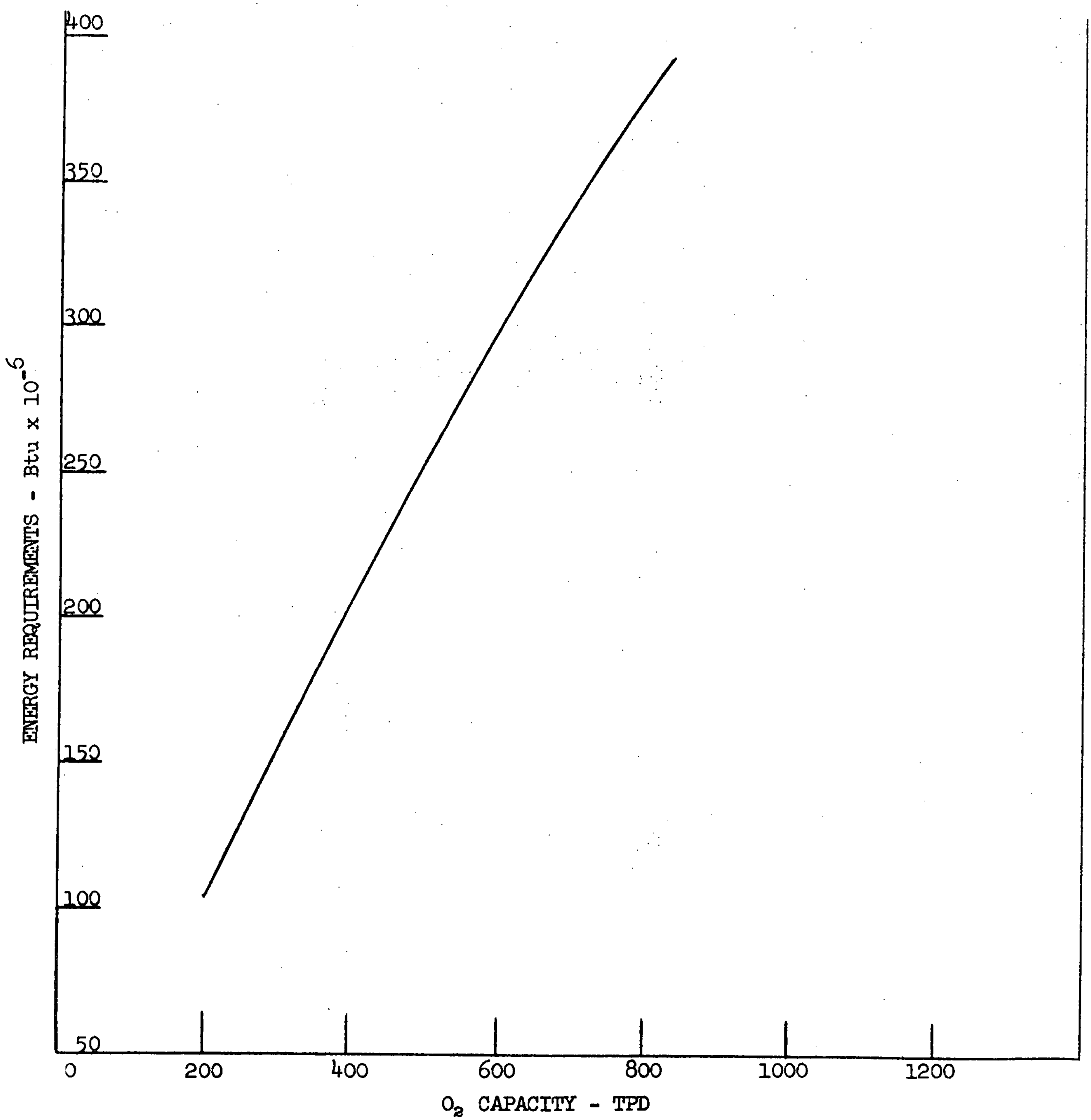


Figure 24

ENERGY REQUIREMENTS FOR STEAM DRIVEN AIR PLANT PLUS LIQUEFIER LOX/LIN RATIO = 2.0

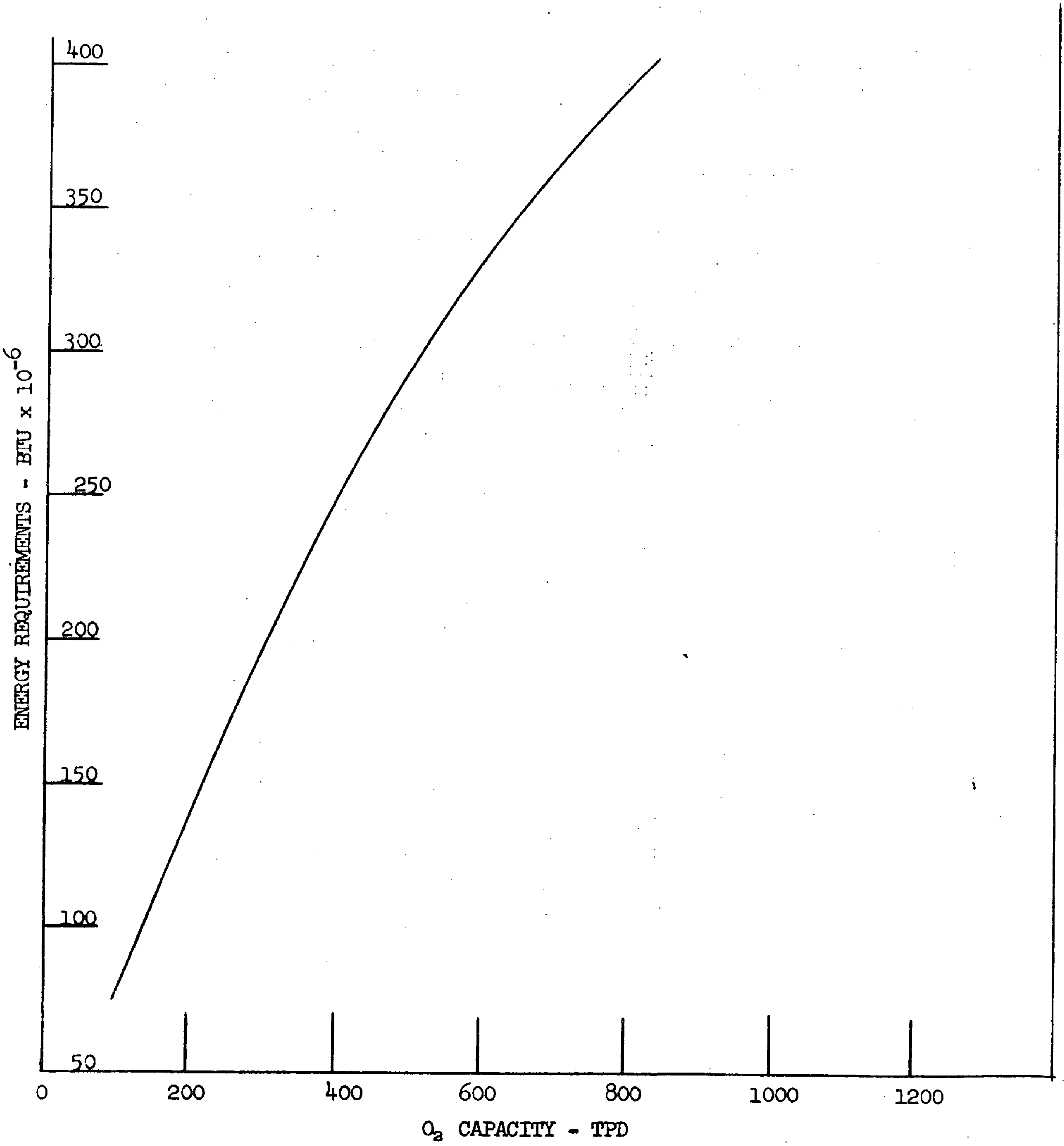


Figure 25

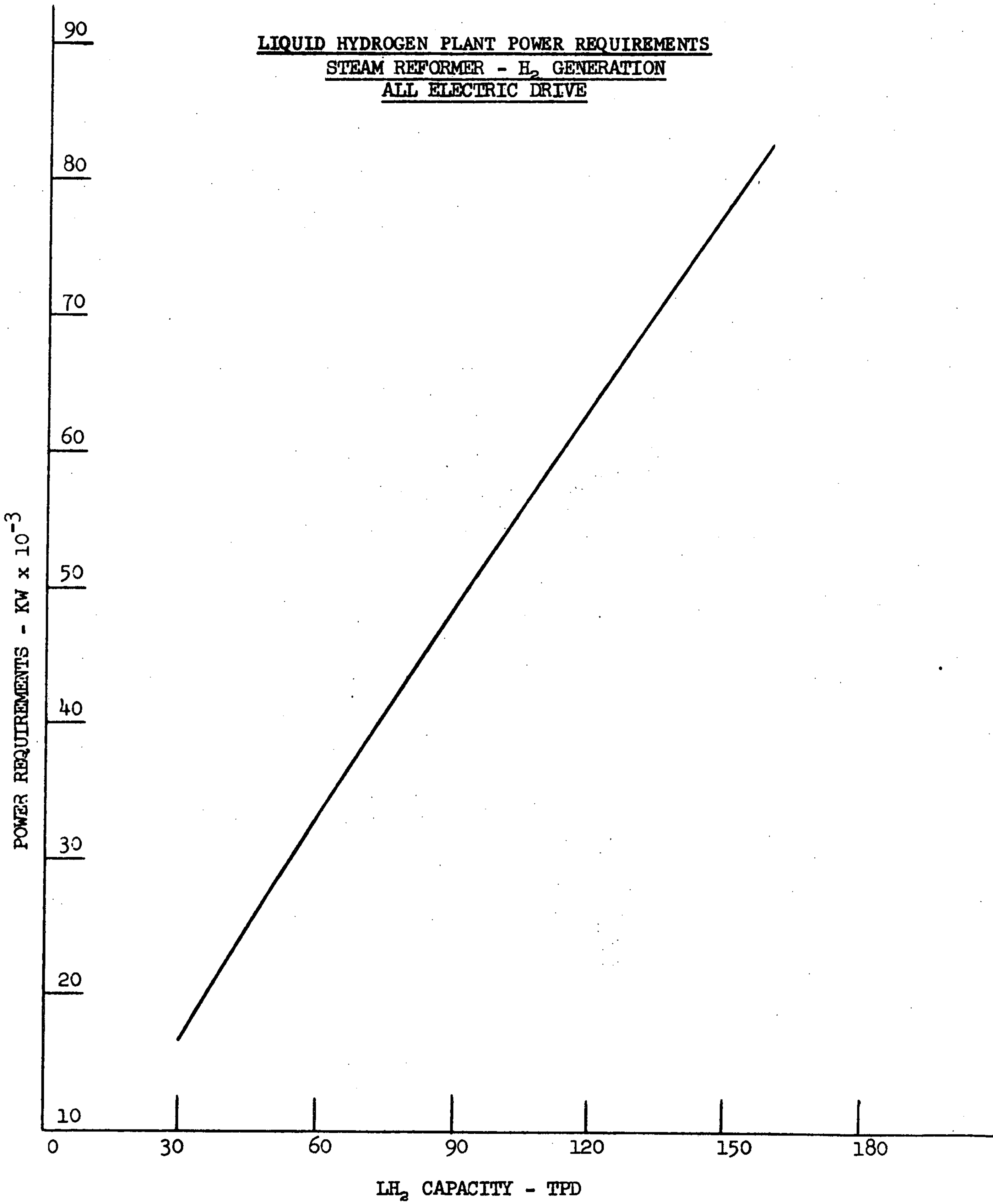

LIQUID HYDROGEN PLANT POWER REQUIREMENTS
STEAM REFORMER - H_2 GENERATION
ALL ELECTRIC DRIVE
POWER REQUIREMENTS - KW x 10^{-3}
90
80
70
60
50
40
30
20
10
0
30
60
90
120
150
180
LH_2 CAPACITY - TPD

Figure 26

LIQUID HYDROGEN PLANT POWER REQUIREMENTS
ELECTRIC DRIVEN LH_2 RECYCLE COMPRESSORS

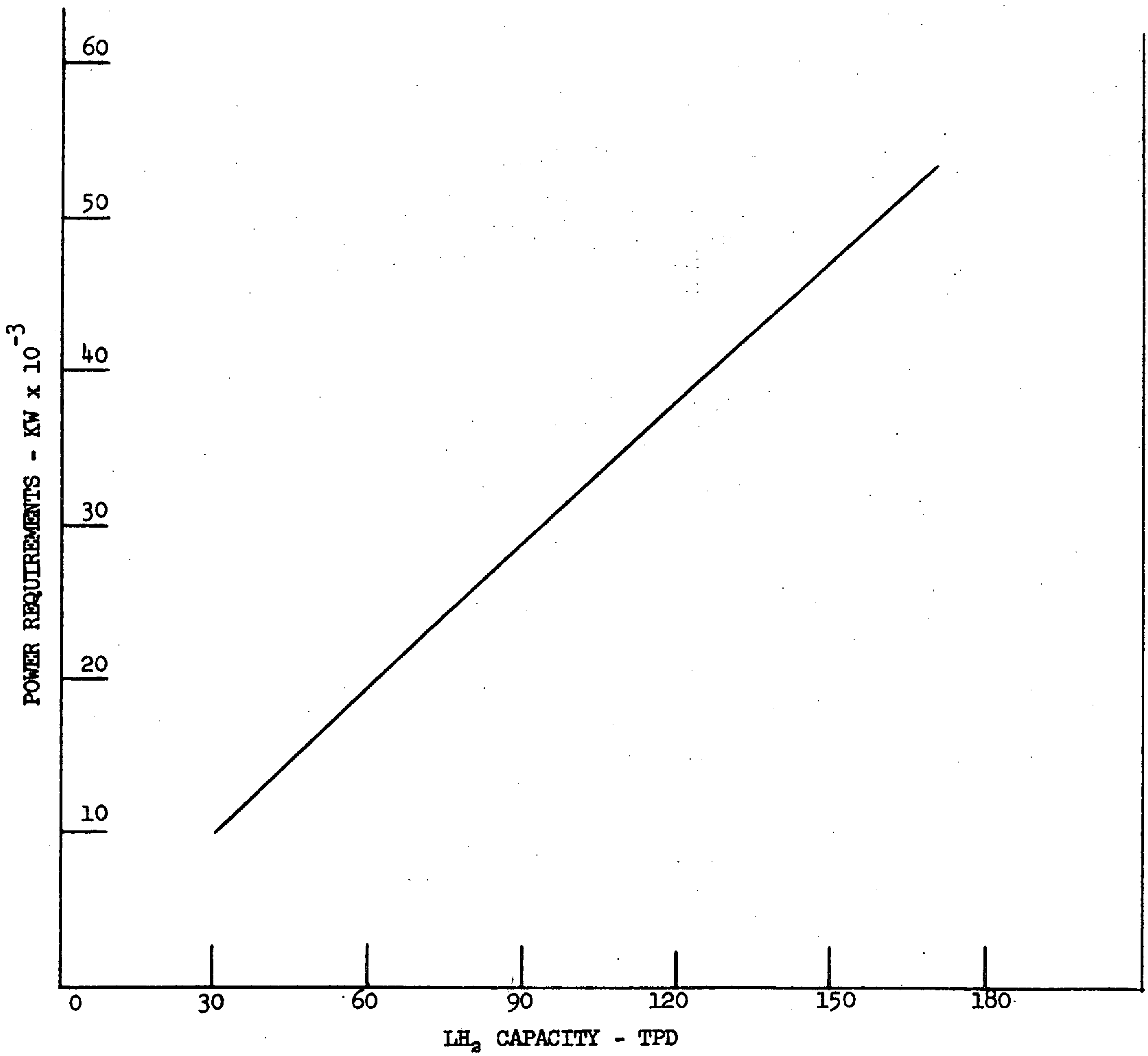


Figure 27

LIQUID HYDROGEN PLANT
ENERGY REQUIREMENTS
STEAM REFORMER-H_2 GENERATION
ALL ELECTRIC DRIVE

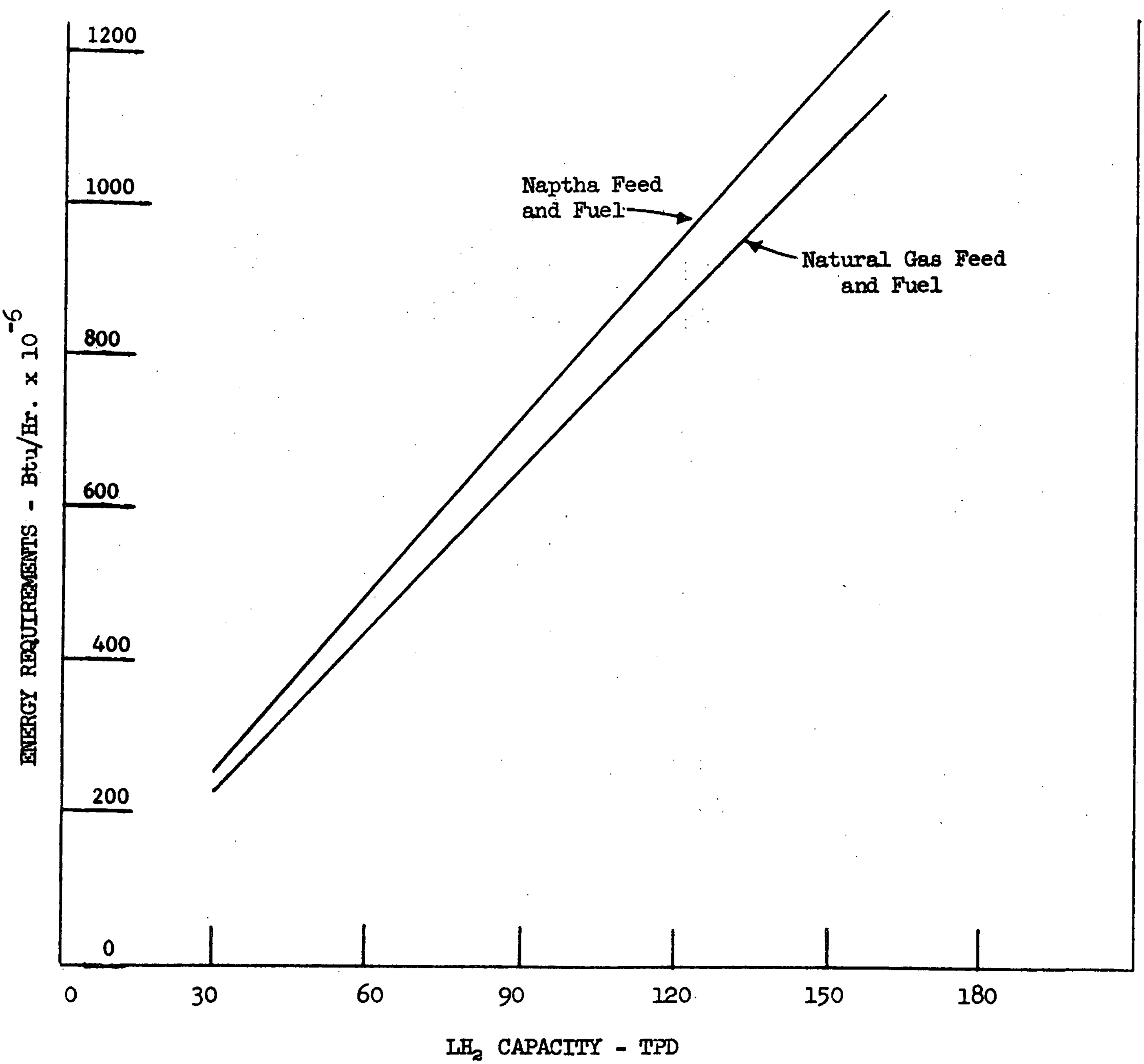


Figure 28

LIQUID HYDROGEN PLANT
ENERGY REQUIREMENTS
STEAM REFORMER - H_2 GENERATION
GAS TURBINE DRIVE AIR AND N_2 RECYCLE COMPRESSORS
OTHER CENTRIFUGAL COMPRESSORS STEAM DRIVE
ELECTRIC DRIVEN LH_2 RECYCLE COMPRESSORS

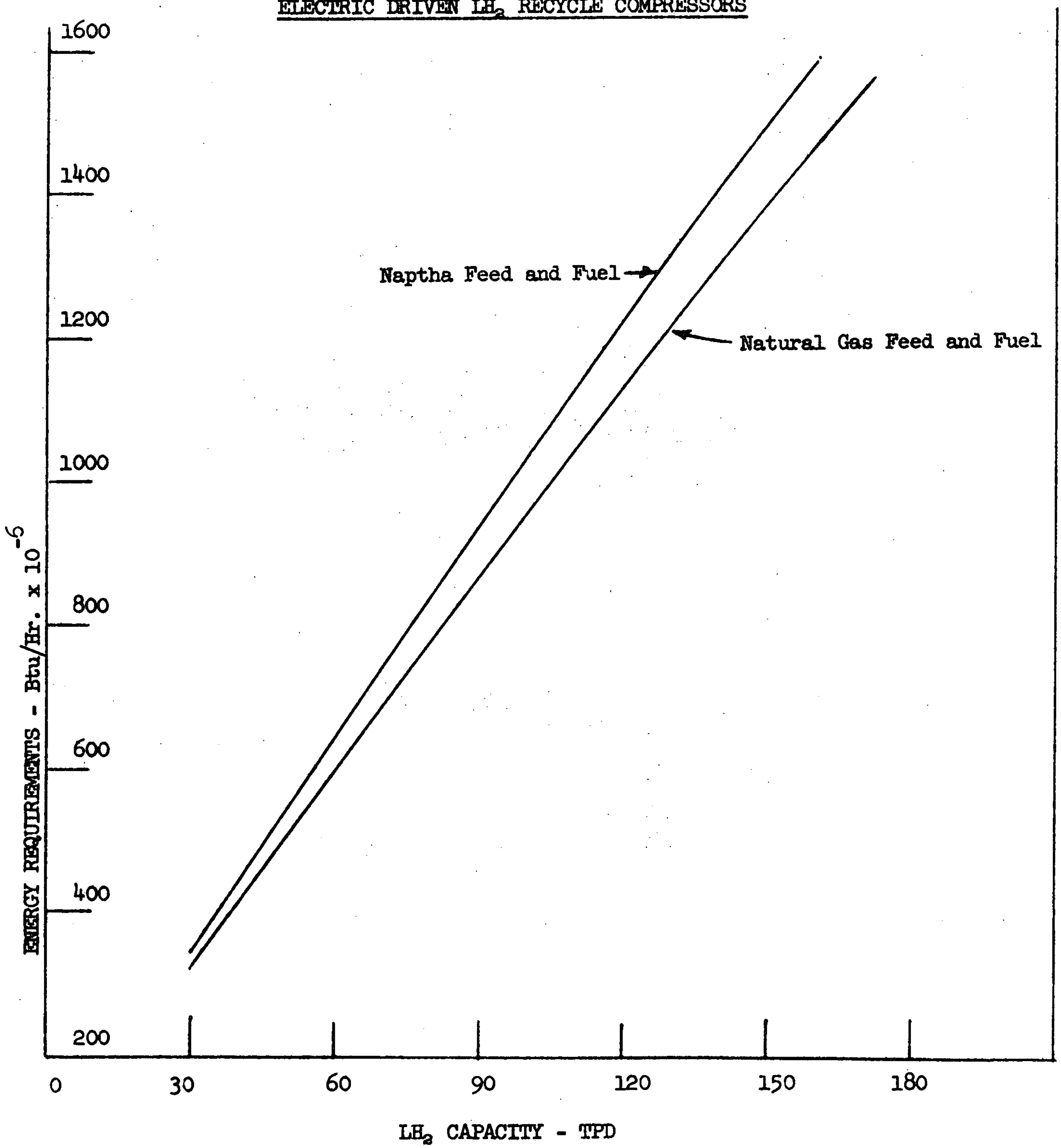
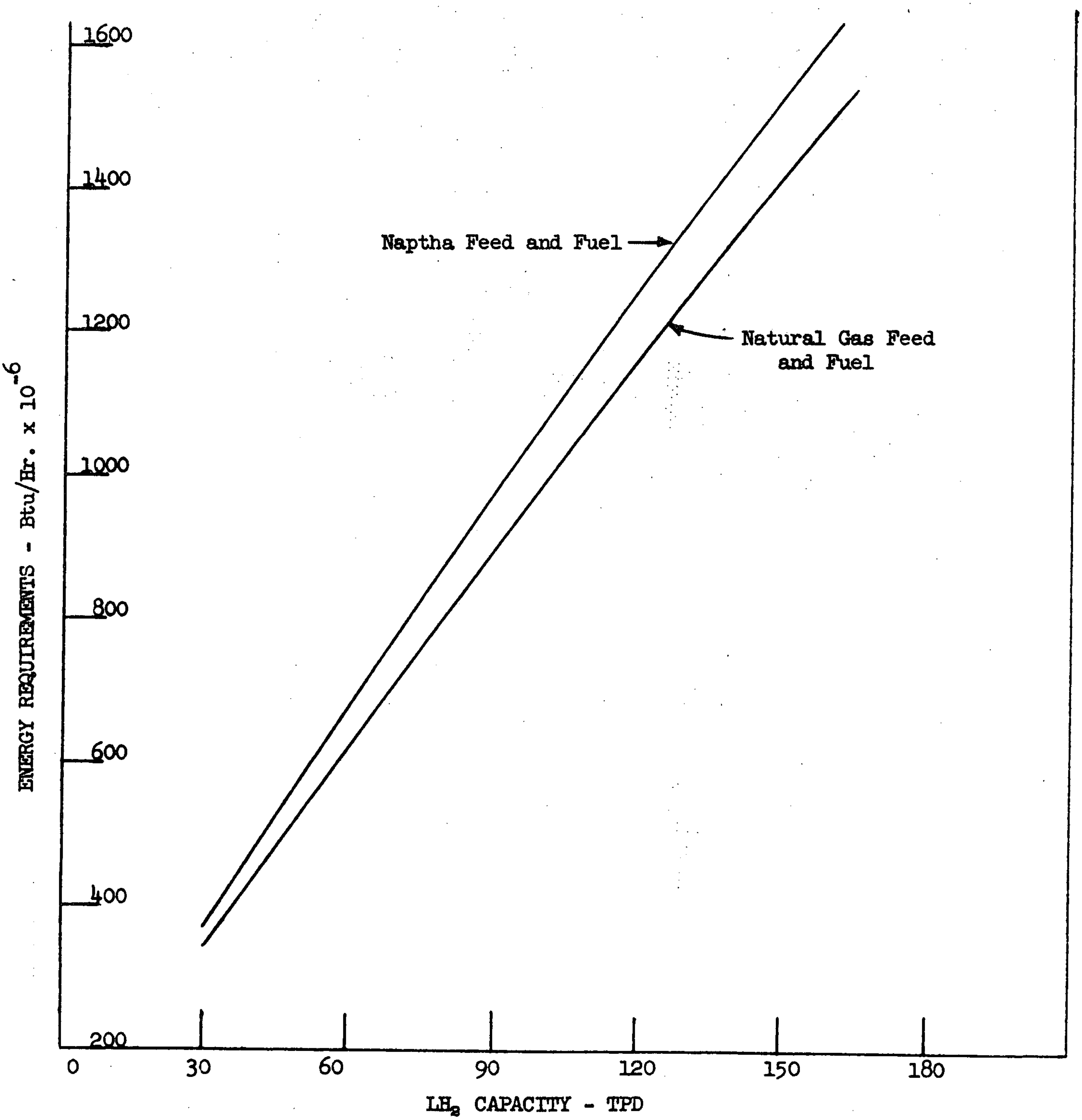


Figure 29

LIQUID HYDROGEN PLANT ENERGY REQUIREMENTS
STEAM DRIVEN CENTRIFUGAL COMPRESSORS
ELECTRIC DRIVEN LH_2 RECYCLE COMPRESSORS



3

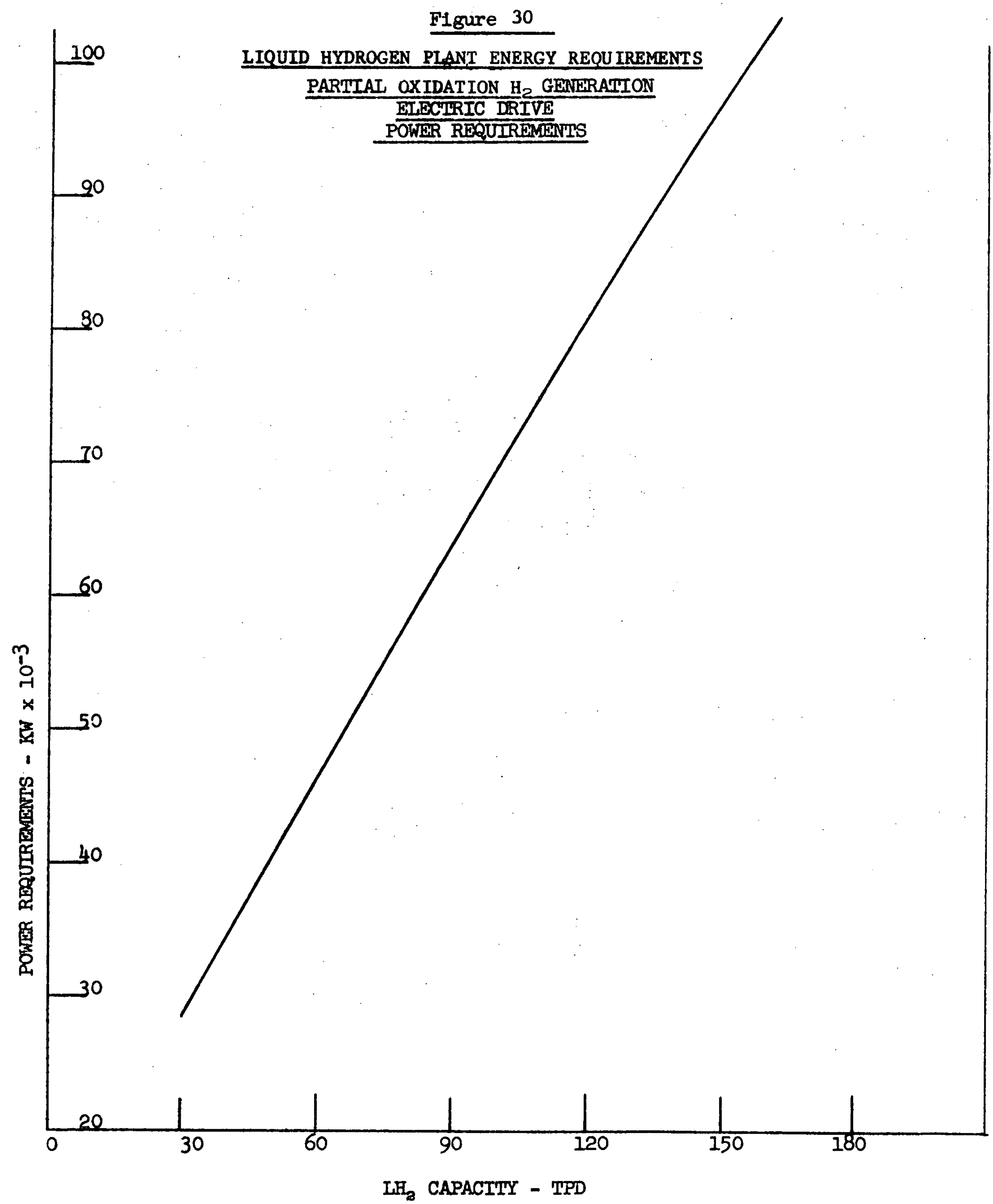


Figure 30
LIQUID HYDROGEN PLANT ENERGY REQUIREMENTS
PARTIAL OXIDATION H_2 GENERATION
ELECTRIC DRIVE
POWER REQUIREMENTS
100
90
80
70
60
50
40
30
20
0
30
60
90
120
150
180
POWER REQUIREMENTS - KW x 10^{-3}
LH_2 CAPACITY - TPD

Figure 31

LIQUID HYDROGEN PLANT ENERGY REQUIREMENTS
PARTIAL OXIDATION H_2 GENERATION
ENERGY REQUIREMENTS

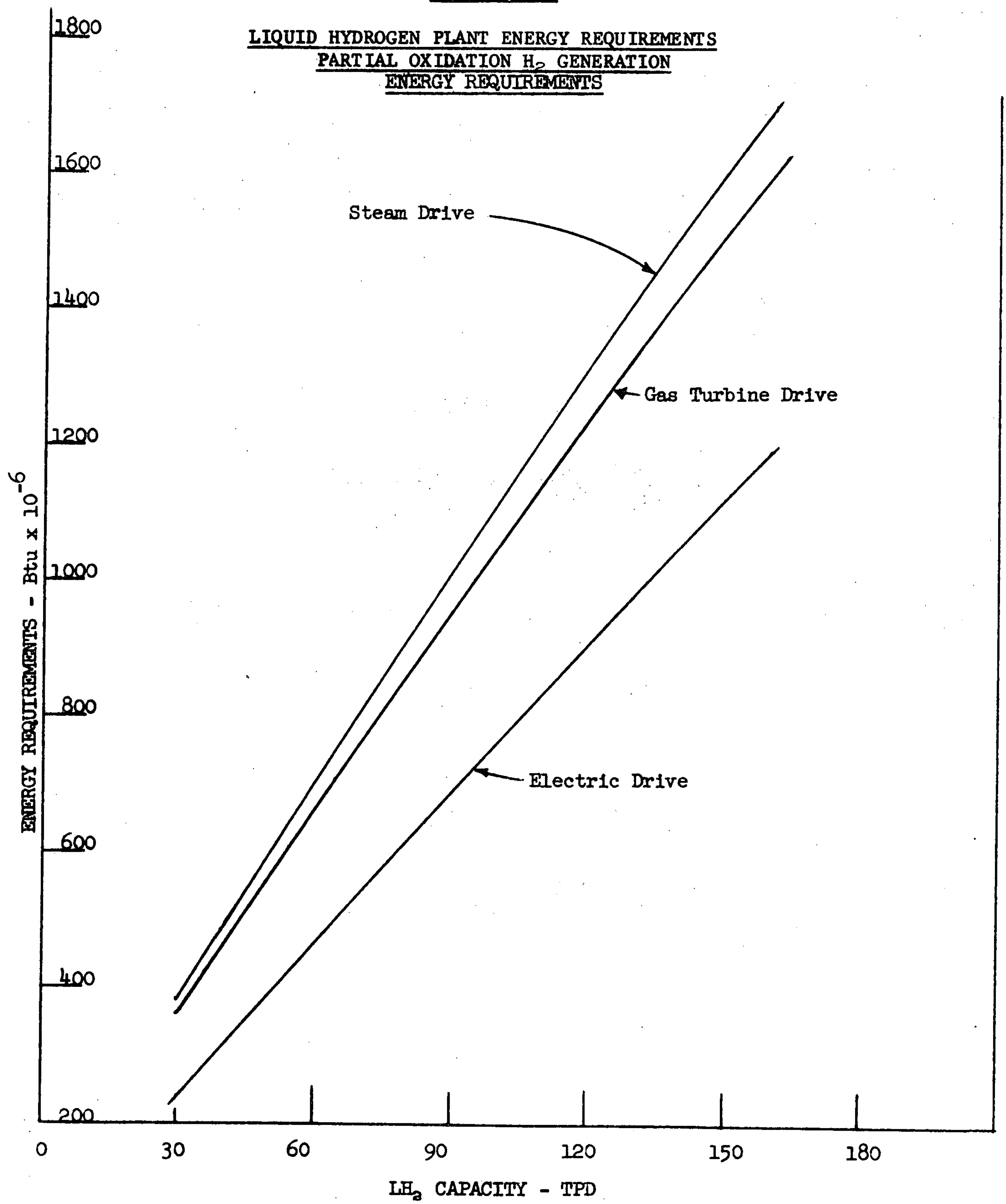


Figure 32

INTEGRATED PROPELLANT PRODUCTION PLANT POWER REQUIREMENTS
STEAM REFORMER H_2 GENERATION
ALL ELECTRIC DRIVE

PRODUCT RATIO = 1 TPD LH_2 : 5 TPD LOX : 2.5 TPD LIN

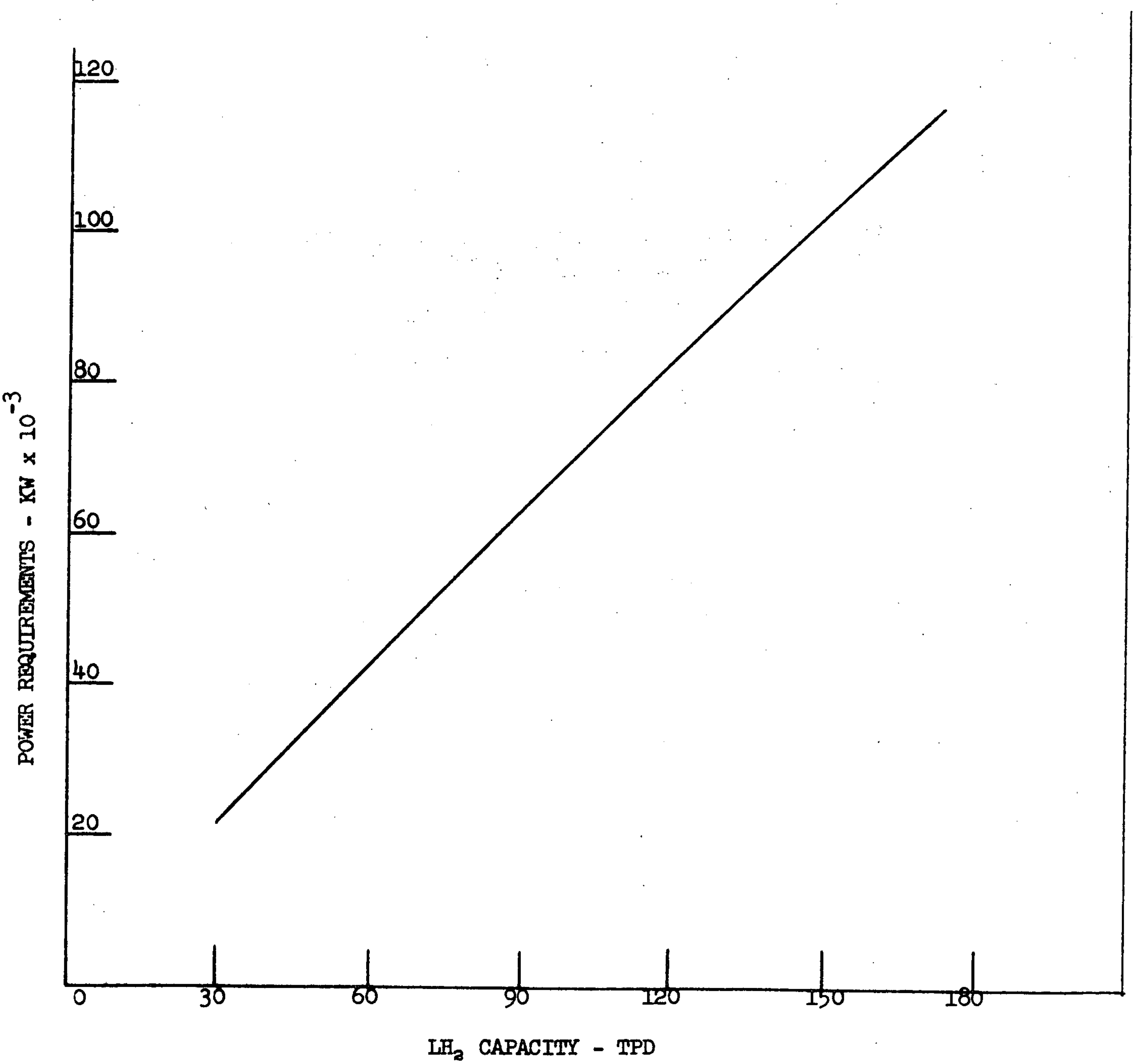


Figure 33

INTEGRATED PROPELLANT PRODUCTION PLANT
ENERGY REQUIREMENTS
STEAM REFORMER-H_2 GENERATION
GAS TURBINE DRIVE AIR AND N_2 RECYCLE COMPRESSORS
OTHER CENTRIFUGAL COMPRESSORS STEAM DRIVE
ELECTRIC DRIVEN LH_2 RECYCLE COMPRESSORS

PRODUCT RATIO = 1 TPD LH_2 : 5 TPD LOX : 2.5 TPD LIN

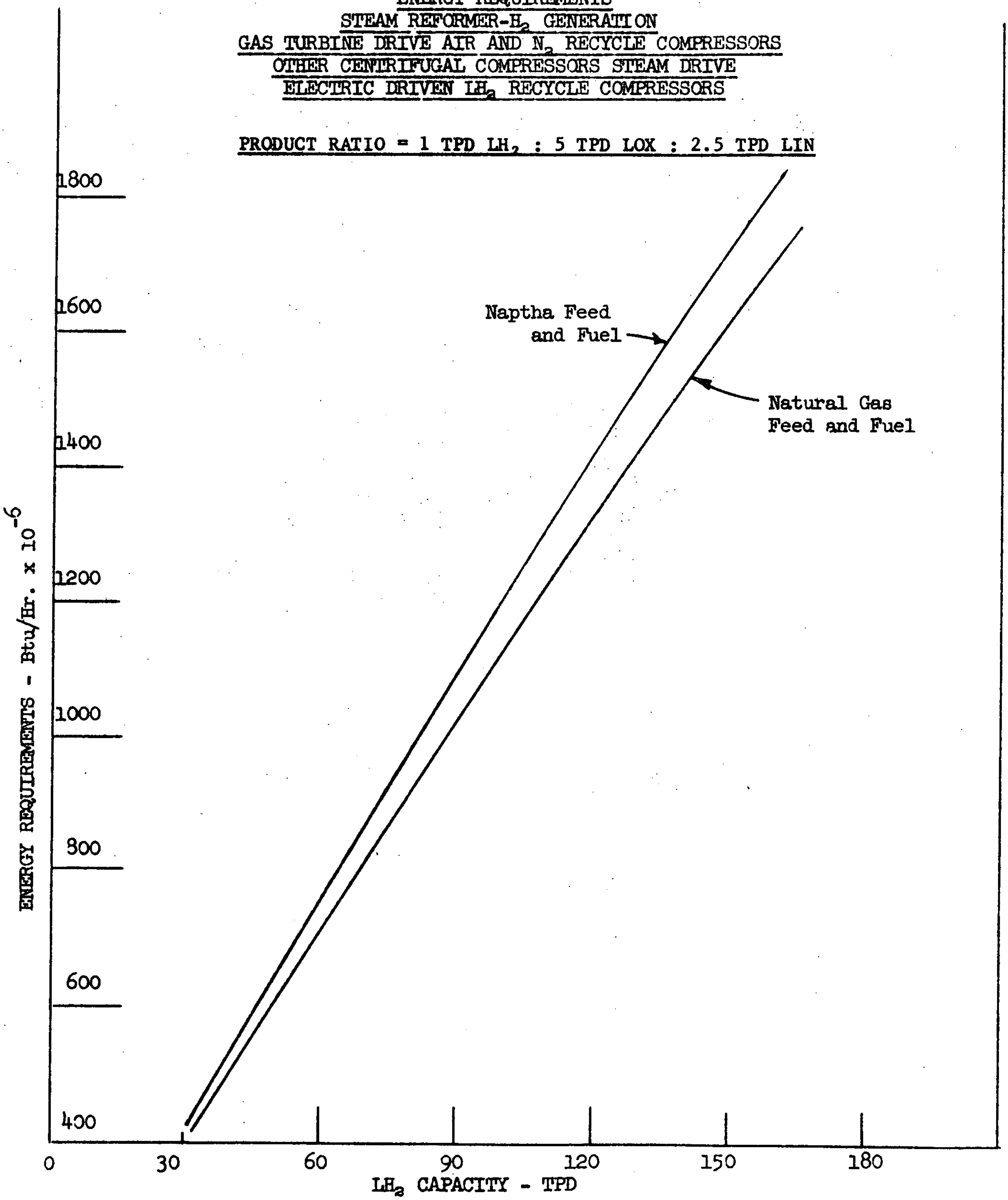


Figure 34

INTEGRATED PROPELLANT PRODUCTION PLANT
ENERGY REQUIREMENTS
STEAM REFORMER - H_2 GENERATION
STEAM DRIVEN CENTRIFUGAL COMPRESSORS
ELECTRIC DRIVEN LH_2 RECYCLE COMPRESSORS

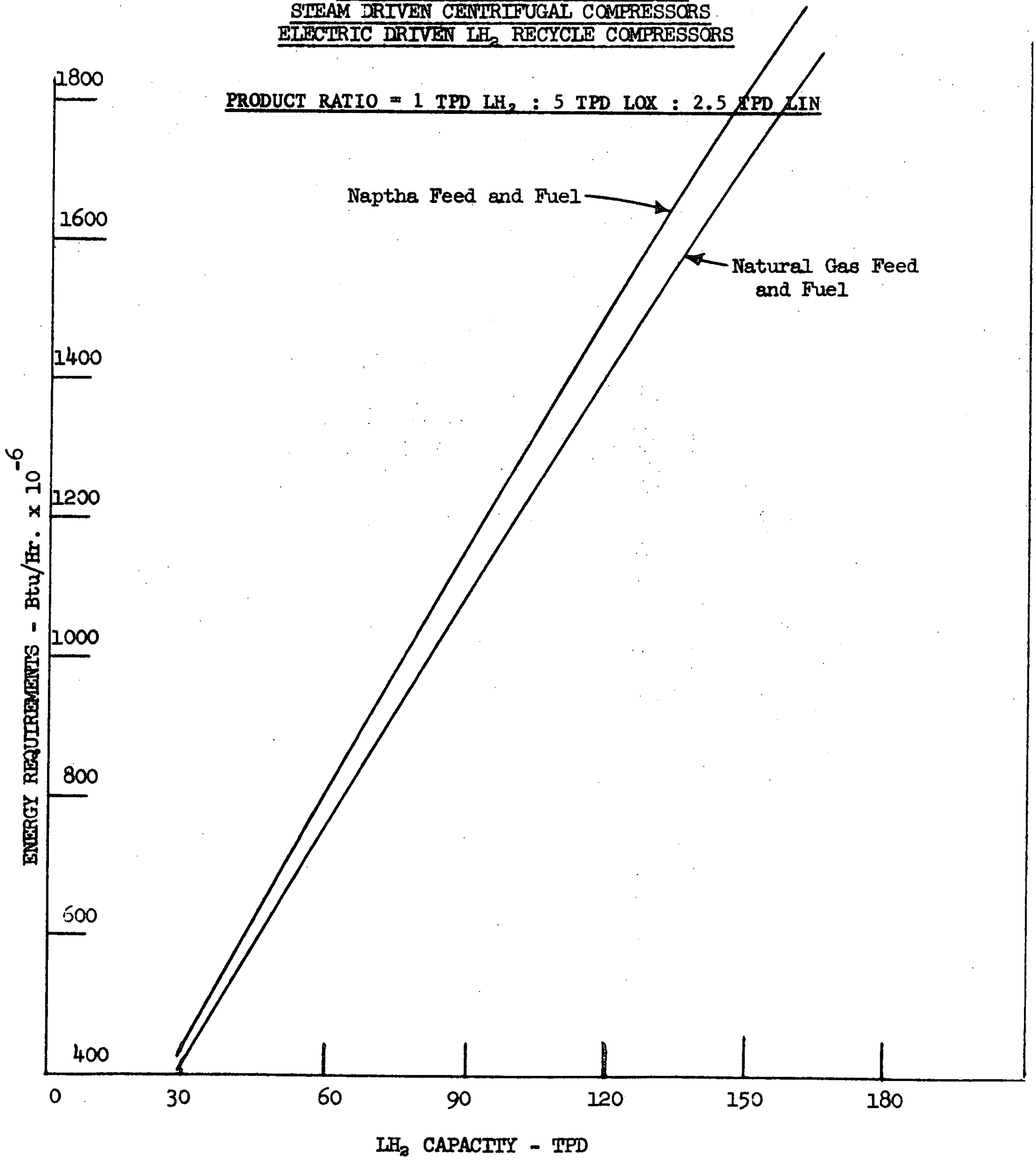


Figure 35

INTEGRATED PROPELLANT PRODUCTION PLANT POWER REQUIREMENTS
PARTIAL OXIDATION H_2 GENERATION
ALL ELECTRIC DRIVE

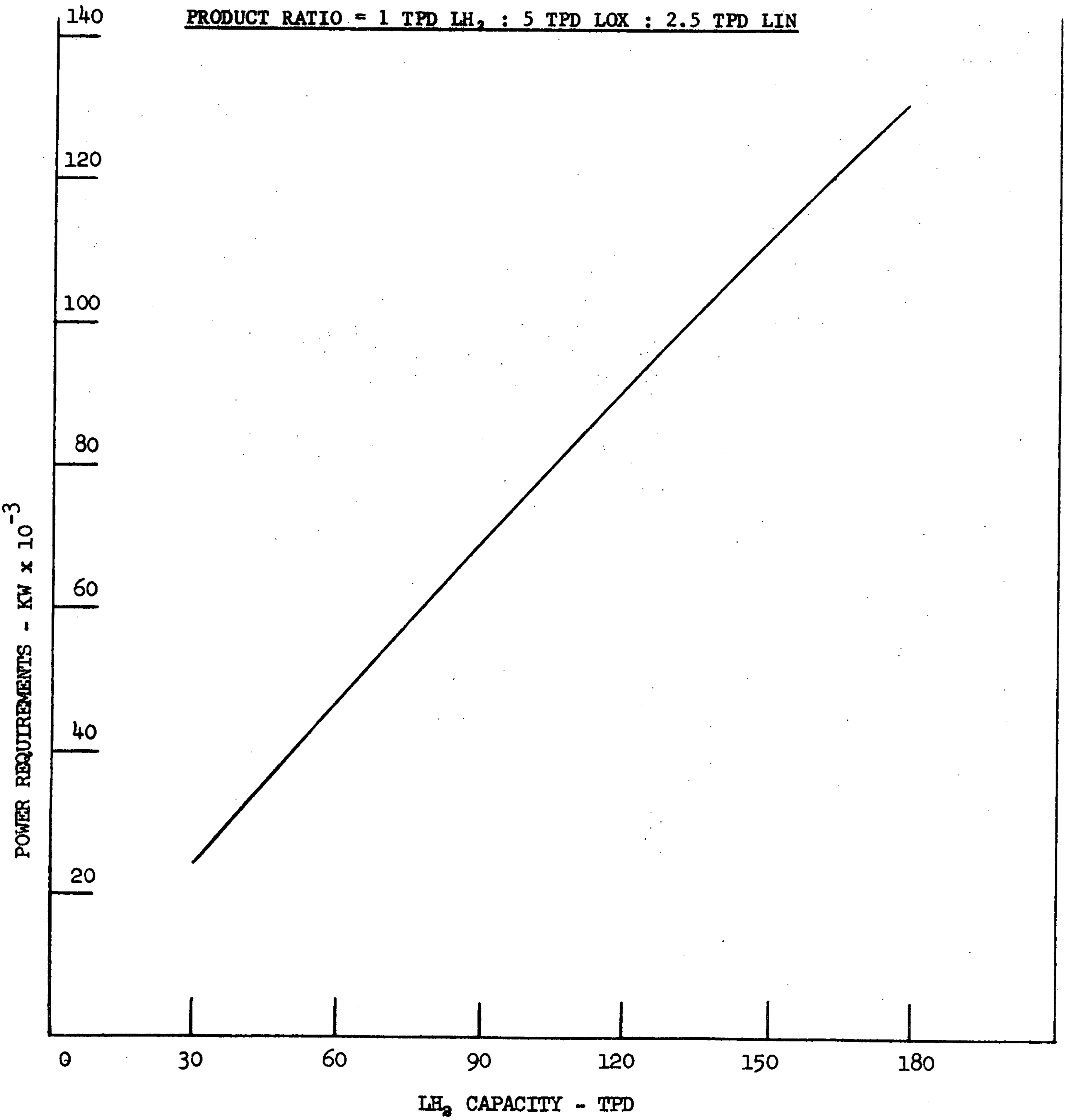


Figure 36

INTEGRATED PROPELLANT PRODUCTION PLANT
ENERGY REQUIREMENTS
PARTIAL OXIDATION H_2 GENERATION

PRODUCT RATIO = 1 TPD LH_2 : 5 TPD LOX : 2.5 TPD LIN

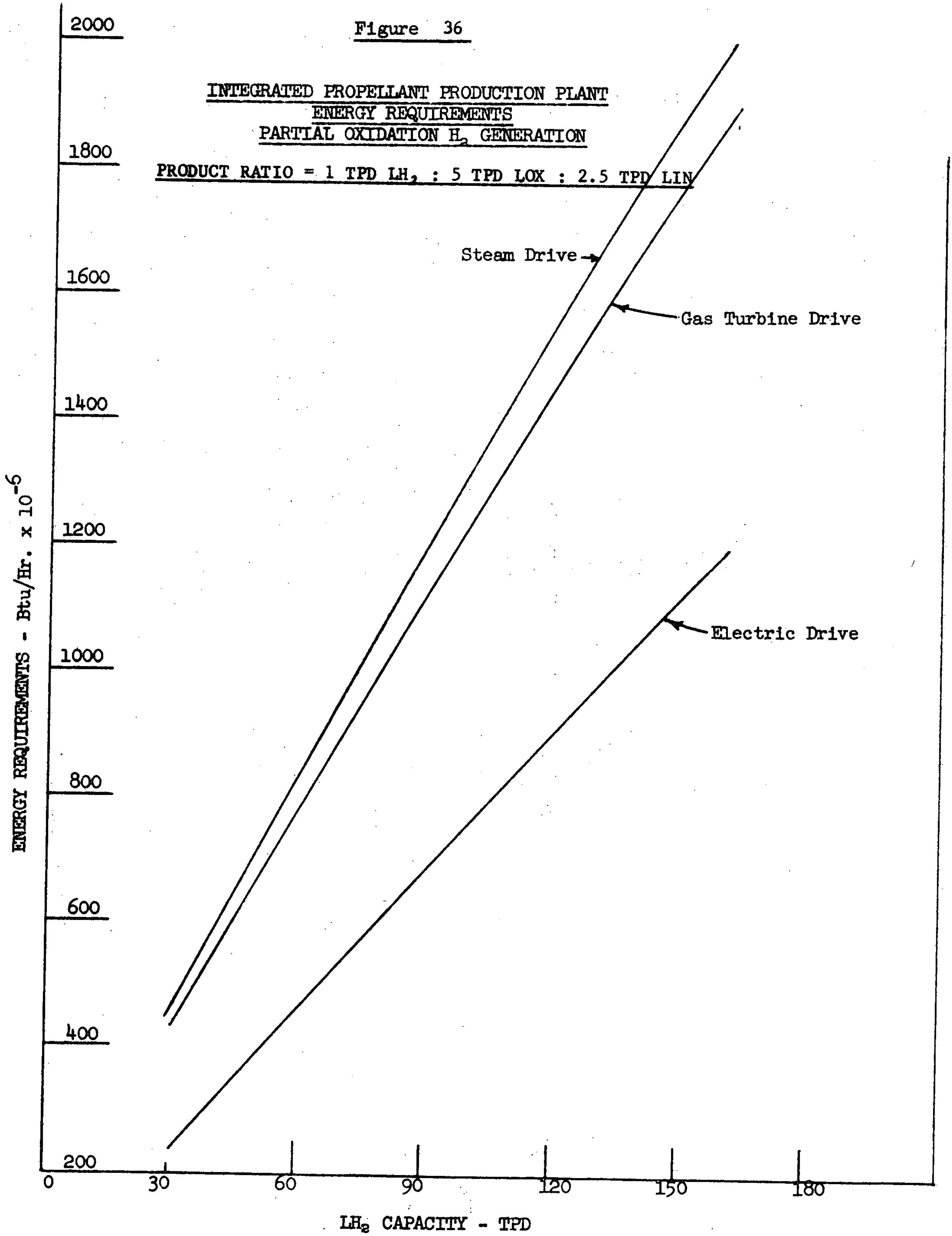


Figure 37

INTEGRATED PROPELLANT PRODUCTION PLANT POWER REQUIREMENTS
STEAM REFORMER H_2 GENERATION
LNG FUEL AND REACTION GAS
ALL ELECTRIC DRIVE

PRODUCT RATIO = 1 TPD LH_2 : 5 TPD LOX : 2.5 TPD LIN

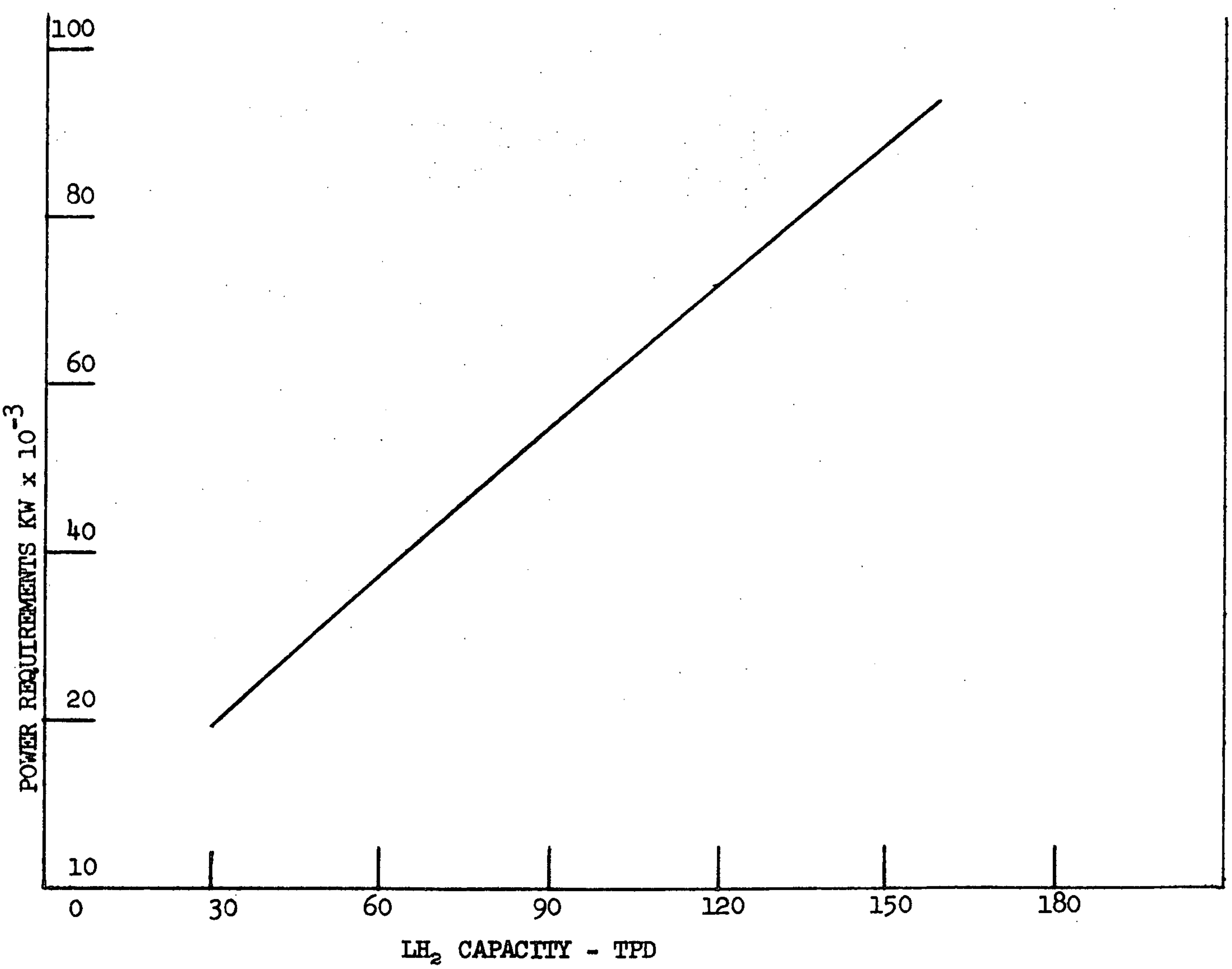


Figure 38

INTEGRATED PROPELLANT PRODUCTION PLANT ENERGY REQUIREMENTS
STEAM REFORMER H_2 GENERATION
LNG FUEL AND REACTION GAS

PRODUCT RATIO = 1 TPD LH_2 : 5 TPD LOX : 2.5 TPD LIN

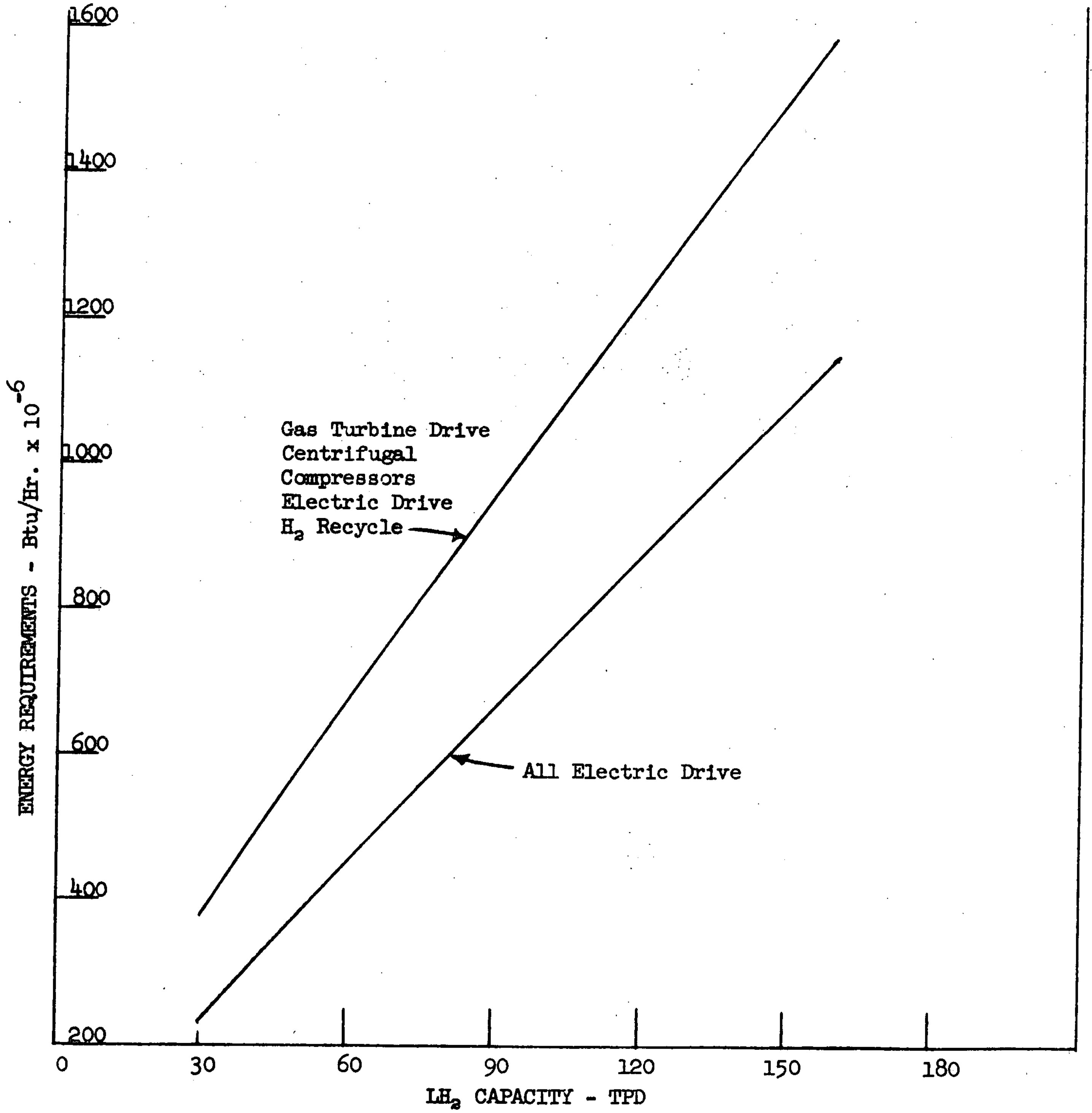


Figure 39

EFFECT OF PRODUCT PARAHYDROGEN
CONTENT ON PRODUCTION CAPABILITY

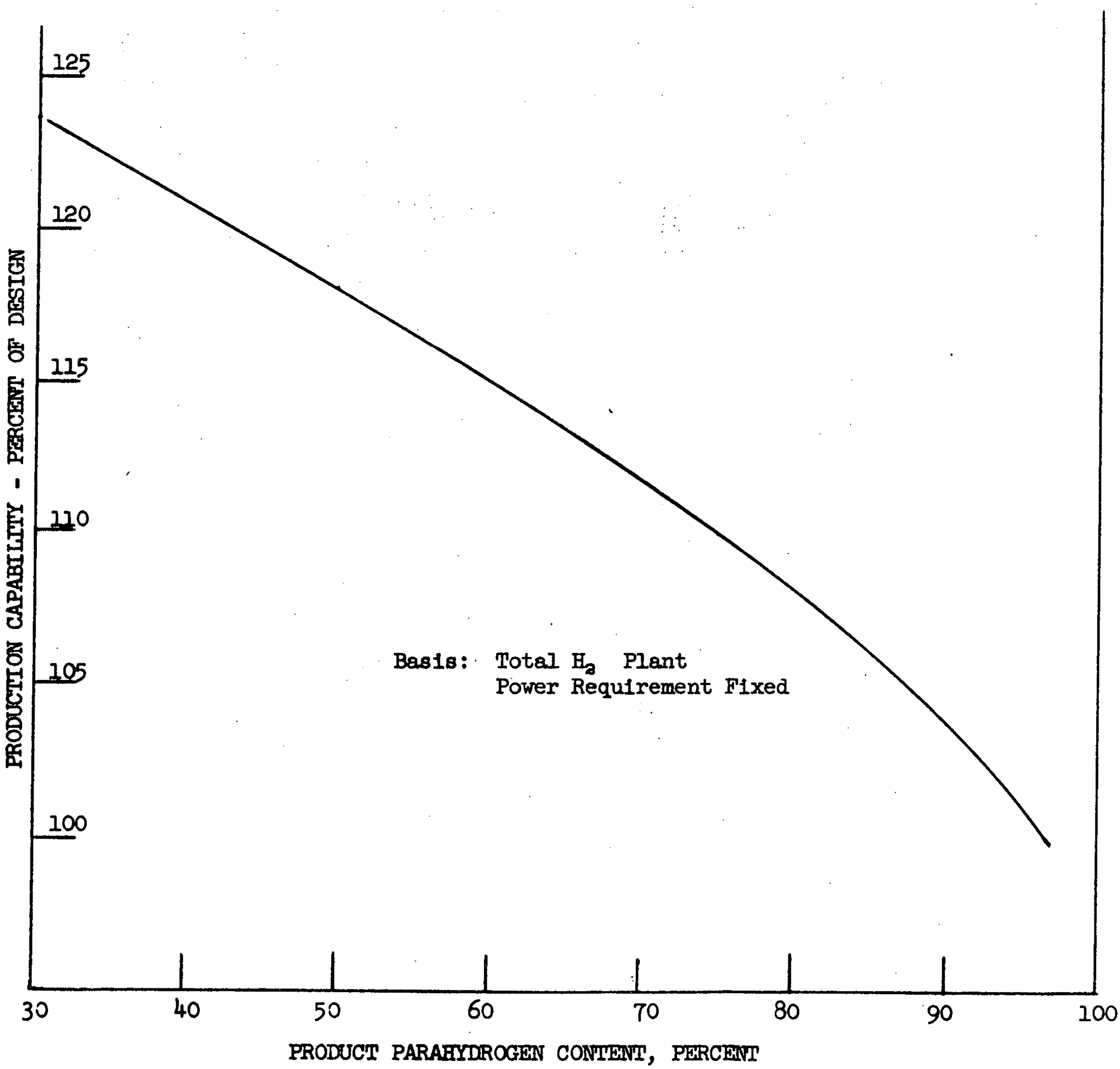


Figure 41

DEUTERIUM RECOVERY COSTS

140 TONS PER DAY LH_2 PROCESSED

FROM 160 TPD DESIGN LH_2 PLANT

60 TONS PER YR DEUTERIUM

OXIDE (D_2O) PRODUCED

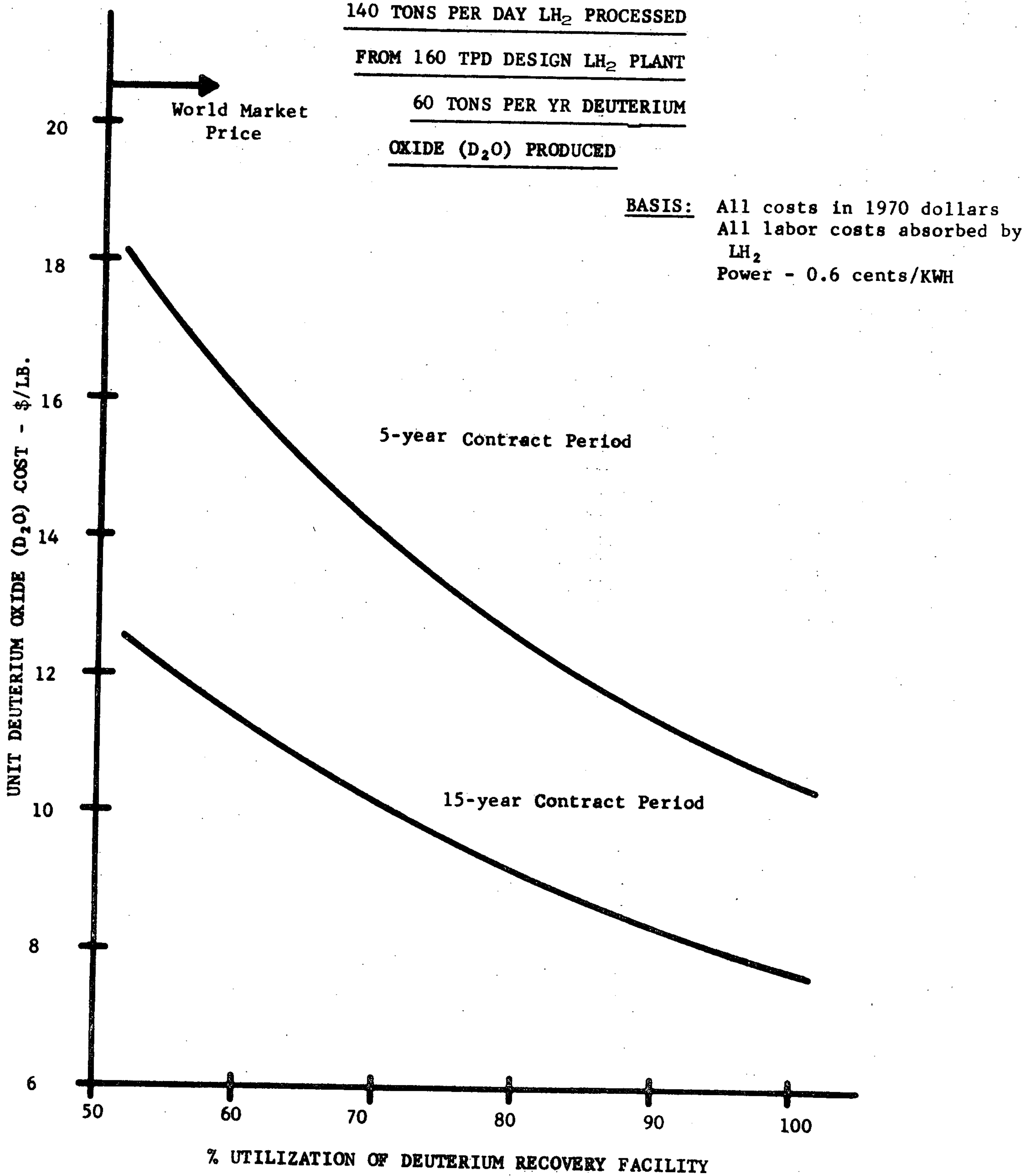


Figure 43

COST OF METHANOL VS LH_2 PLANT UTILIZATION

160 TPD INTEGRATED PROPELLANT PRODUCTION PLANT

BASIS: All costs in 1970 dollars

a) All labor costs absorbed by LH_2
b) Unit cost is consumables only
c) Investment cost is 33%/year
d) Fuel - 45¢/MM Btu
e) Power - 0.6¢/KWH
f) Investment is incremental investment for making methanol
g) Unit cost is incremental unit cost for making methanol

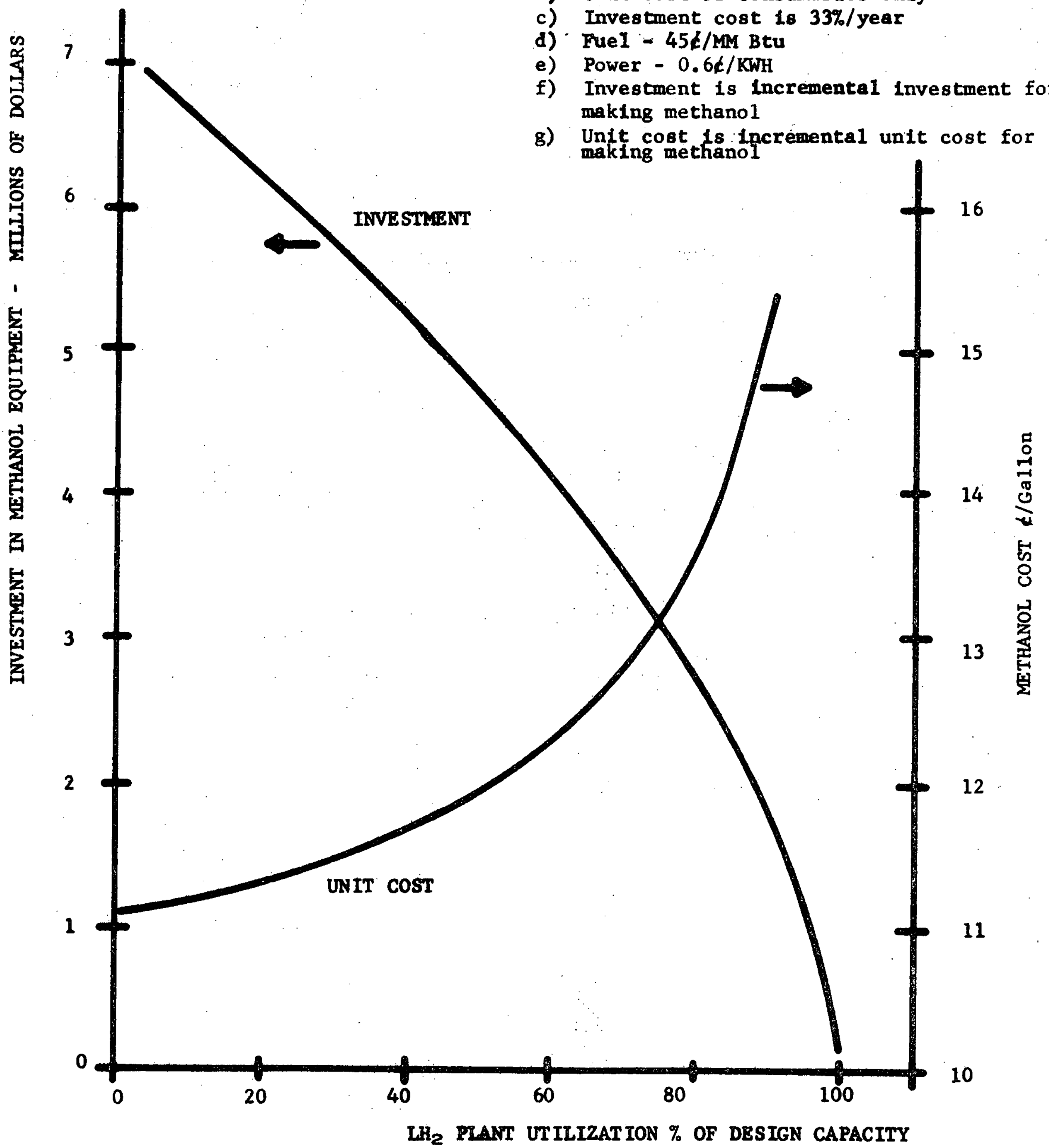


Figure 45

LH$_2$ VACUUM INSULATED

STORAGE TANK COSTS

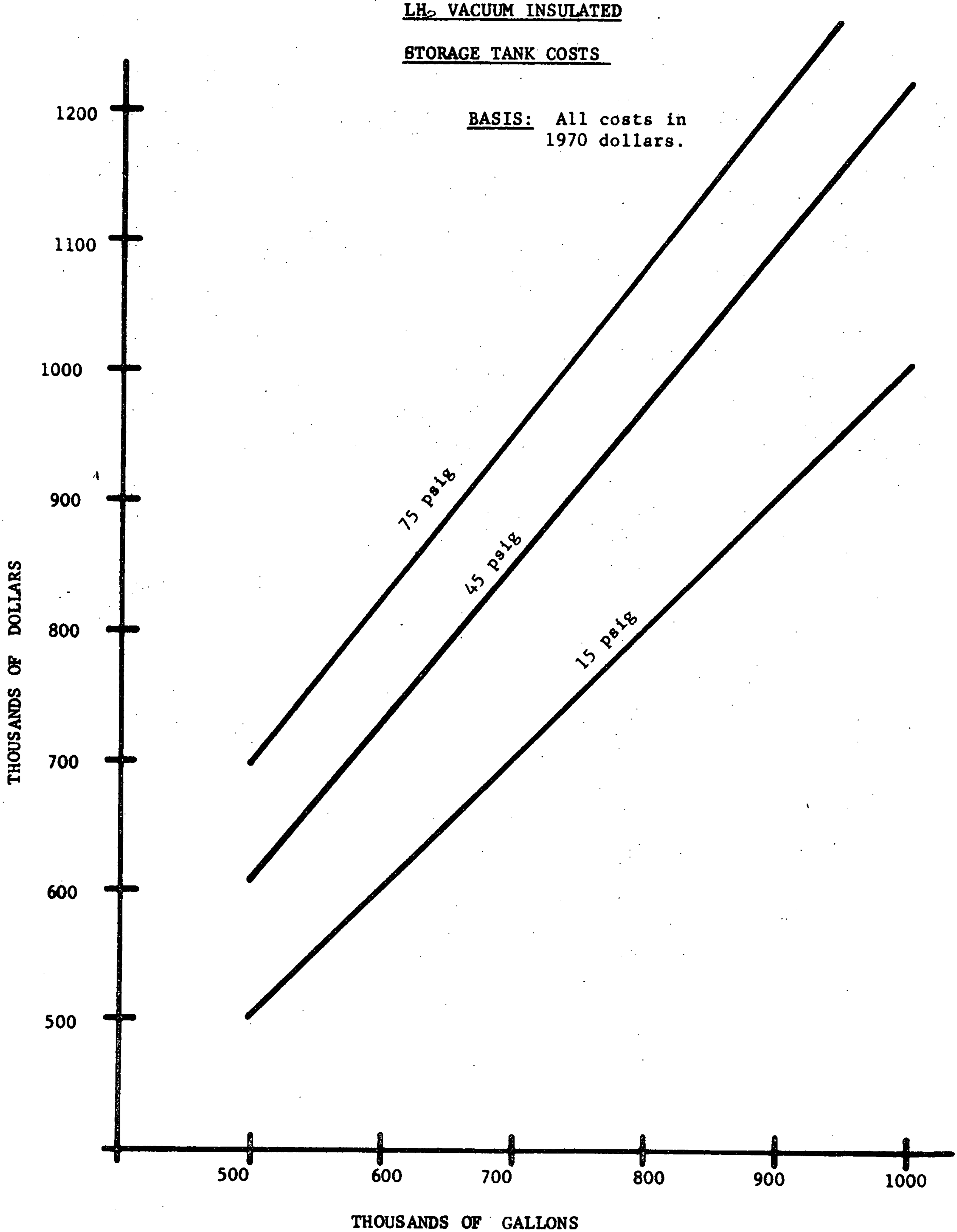
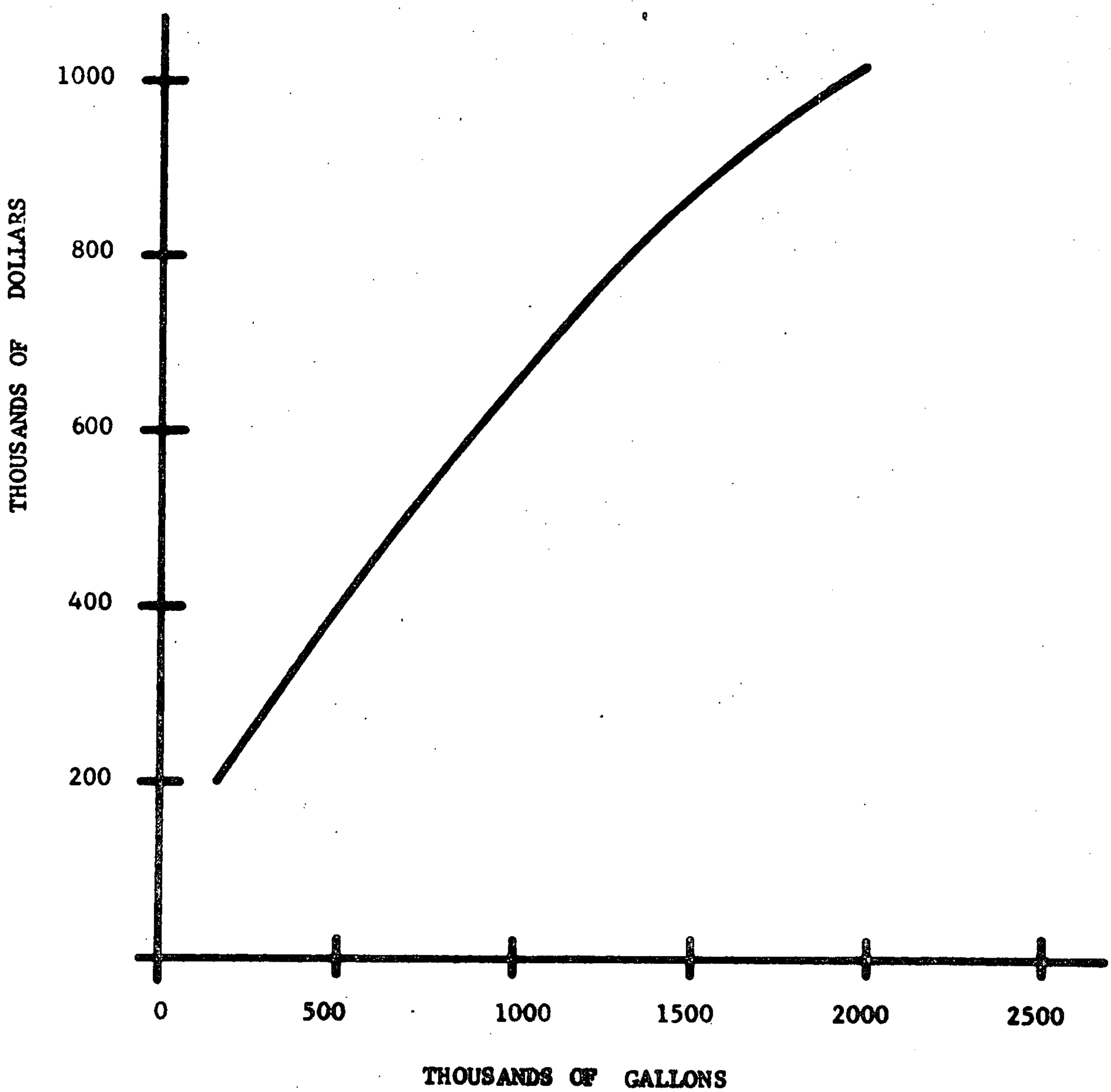


Figure 46

LOW PRESSURE LOX AND LIN

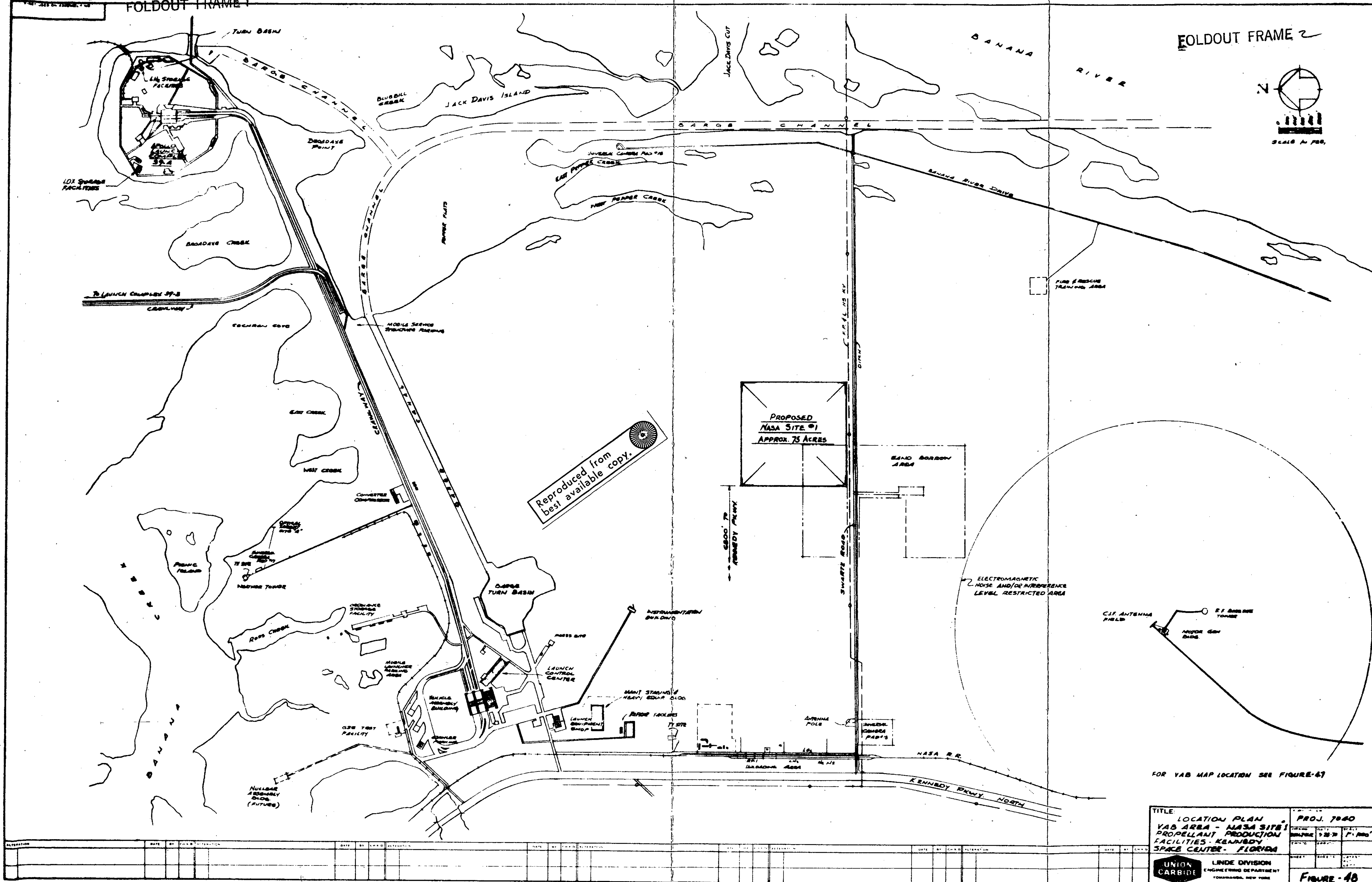
STORAGE COSTS

BASIS: All costs in 1970 dollars.



FOLDOUT FRAME 1

FOLDOUT FRAME 2



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TITLE: LOCATION PLAN VAB AREA - NASA SITE 1 PROPELLANT PRODUCTION FACILITIES - KENNEDY SPACE CENTER - FLORIDA

PROJ. 7940

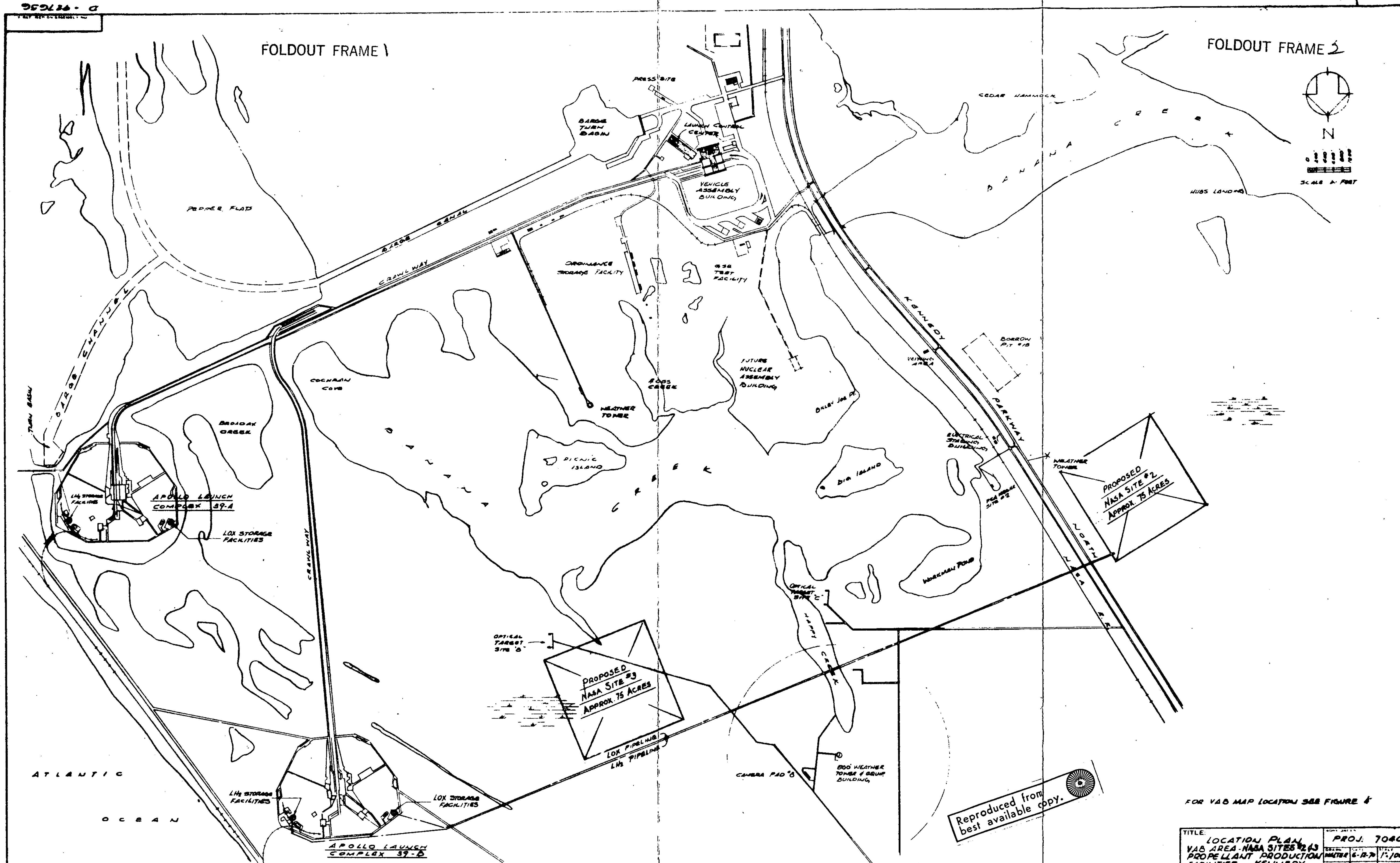
UNION CARBIDE — LINDE DIVISION, ENGINEERING DEPARTMENT, TONAWANDA, NEW YORK

FIGURE - 48

D-927654

FOLDOUT FRAME 1

FOLDOUT FRAME 2



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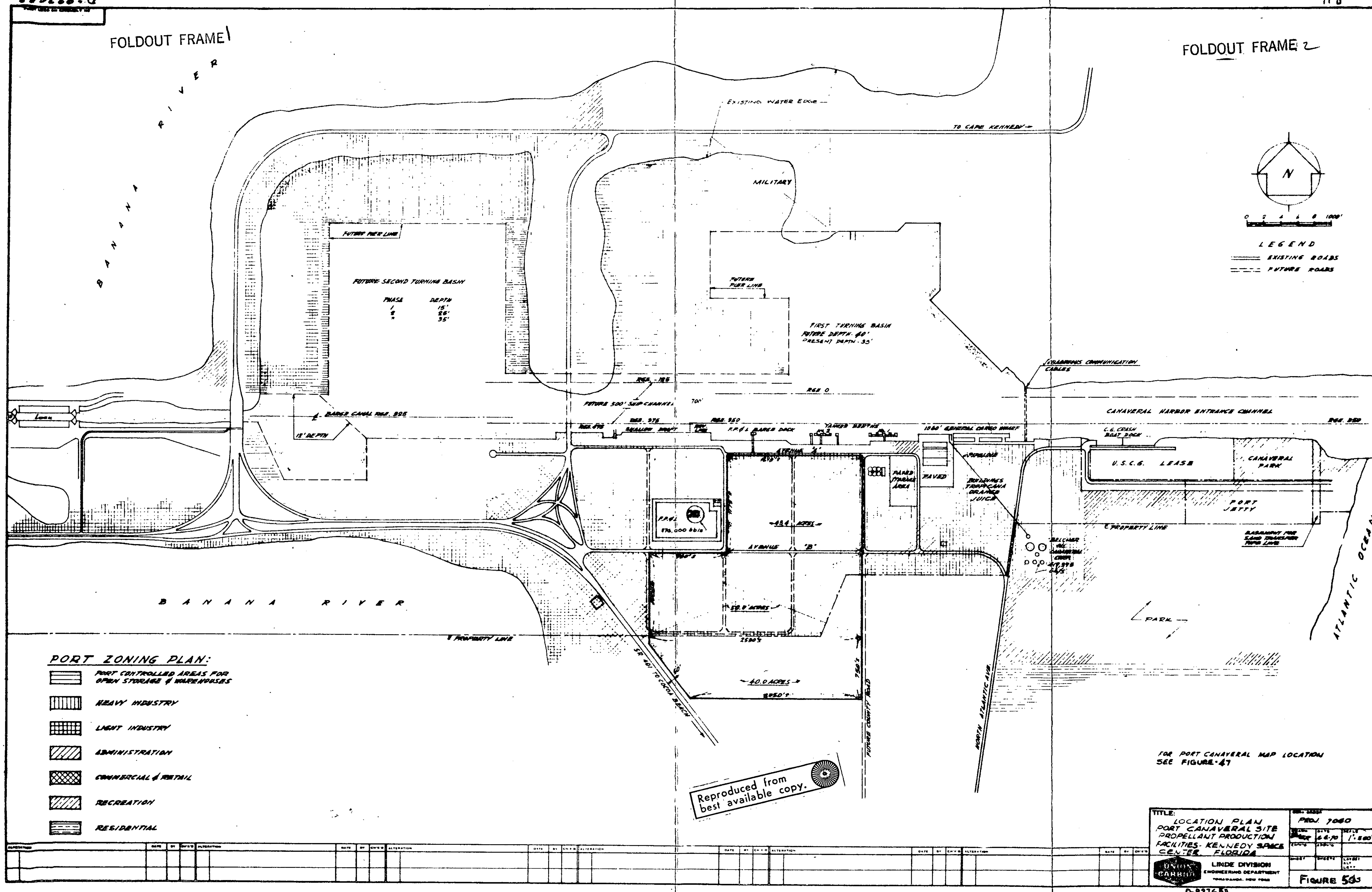
PROJ. 7040

WALTER 6-13-70 1"=1000'

UNION CARBIDE — LINDE DIVISION ENGINEERING DEPARTMENT TONAWANDA, NEW YORK

FIGURE 49

D-927656


FOLDOUT FRAME 1
FOLDOUT FRAME 2
BANANA RIVER
EXISTING WATER EDGE
TO CAPE KENNEDY
MILITARY
FUTURE PIER LINE
FUTURE SECOND TURNING BASIN
PHASE DEPTH
1 15'
2 25'
3 35'
FUTURE PIER LINE
FIRST TURNING BASIN
FUTURE DEPTH 40'
PRESENT DEPTH 35'
SUBMARINE COMMUNICATION CABLES
RGE 0
FUTURE 500' SHIP CHANNEL
700'
BARGE CANAL RGE. 805
12' DEPTH
CANAVERAL HARBOR ENTRANCE CHANNEL
RGE. 350
RGE. 975
RGE. 950
SHALLOW DRAFT
F.P.F.L. BARGE DOCK
TANKER BERTHS
1060' GENERAL CARGO WHARF
C.G. CRASH BOAT DOCK
U.S.C.G. LEASE
CANAVERAL PARK
PORT JETTY
PAVED TRAILER AREA
PAVED
BUILDINGS TROPICANA ORANGE JUICE
F.P.F.L. 576,000 bbls
48.4 ACRES
AVENUE "A"
AVENUE "B"
PROPERTY LINE
EASEMENT FOR SAND TRANSFER PIPE LINE
BELCHER OIL CORP. 47,378
PARK
ATLANTIC OCEAN
58.8 ACRES
2590'
40.0 ACRES
2050'
SR 401 TO COCOA BEACH
FUTURE COUNTY ROAD
NORTH ATLANTIC AVE
PROPERTY LINE
LOCK
LEGEND
EXISTING ROADS
FUTURE ROADS
0 2 4 6 8 1000'
N
PORT ZONING PLAN:
PORT CONTROLLED AREAS FOR OPEN STORAGE & WAREHOUSES
HEAVY INDUSTRY
LIGHT INDUSTRY
ADMINISTRATION
COMMERCIAL & RETAIL
RECREATION
RESIDENTIAL
FOR PORT CANAVERAL MAP LOCATION SEE FIGURE 47
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TITLE: LOCATION PLAN PORT CANAVERAL SITE PROPELLANT PRODUCTION FACILITIES · KENNEDY SPACE CENTER, FLORIDA
PROJ. 7060
1" = 500'
UNION CARBIDE
LINDE DIVISION
ENGINEERING DEPARTMENT
TONAWANDA, NEW YORK
FIGURE 56
D-927685

Figure 70

CRYOGENIC DELIVERY

AND

STORAGE SYSTEM EVALUATION MATRIX

CRITERIA	RELATIVE RATINGS* FIGURE (Pipeline)	(Truck)	(Rail)	(Barge)
Number of Transfers	1	4	3	2
Delivery Losses	1	4	3	2
Complexity of "sell-off"	1	4	3	2
Development Effort	4	1	2	3
Emergency Backup Capability	4	1	2	3
Weather and External Interference	1	4	2	3
Flexibility and Growth	4	1	2	3
Delivery System Operations and Maintenance Costs	1	3	2	4
Scheduling Difficulties	1	2	4	3

*RELATIVE RATINGS: 1 = Best
4 = Poorest

Figure 72

TABULATED SUMMARY OF TRUCKING COSTS

Trailer Requirements	Initial Investment	Annual Operating Cost, \$/year	Total Annual Cost, \$/year: 5 yr Contract	Total Annual Cost, \$/year: 15 yr Contract
Capacity (TPD) 160 LH_2/800 LOX/400 LIN				
7 + 2 LH_2 trailers	\$ 1,305,000	\$ 766,000	\$1,200,000	\$1,020,000
7 + 2 LOX "	747,000	747,000	990,000	894,000
4 + 1 LIN "	415,000	445,000	580,000	527,000
23	\$ 2,467,000	\$1,958,000	\$2,770,000	\$2,440,000
Capacity (TPD) 120 LH_2/600 LOX/300 LIN				
6 + 2 LH_2 trailers	\$ 1,160,000	\$ 574,000	\$ 957,000	\$ 802,000
5 + 2 LOX "	581,000	560,000	752,000	674,000
3 + 1 LIN "	332,000	334,000	444,000	399,000
19	\$ 2,073,000	\$1,468,000	\$2,153,000	\$1,875,000
Capacity (TPD) 40 LH_2/200 LOX/100 LIN				
2 + 1 LH_2 trailers	\$ 435,000	\$ 191,000	\$ 335,000	\$ 277,000
2 + 1 LOX "	249,000	187,000	269,000	236,000
1 + 1 LIN "	166,000	111,000	166,000	144,000
7	\$ 850,000	\$ 489,000	\$ 770,000	\$ 657,000

Basis:

1. 4 hour round-trip
2. 8% product losses
3. 24 hour per day storage accessibility
4. \$60 per truck trip operating cost
5. LH_2 trailer - capacity 3.9 tons, cost \$145,000
6. LOX trailer - capacity 20 tons, cost \$83,000
7. LIN trailer - capacity 16.8 tons, cost \$83,000

Figure 73

TABULATED SUMMARY OF RAIL COSTS

Rail Car Requirements		Initial Investment		Annual Operating Cost, $/year		Total Annual Cost, $/year 5 yr Contract	Total Annual Cost, $/year 15 yr Contract
Capacity (TPD) 160 LH_2/800 LOX/400 LIN							
4 LH_2 cars		$1,000,000		$1,246,000			
3 LOX "		360,000		352,000			
2 LIN "		240,000		183,000			
9		1,600,000	Special train	1,781,000			
	Rail siding	400,000	charge -	334,000		$2,775,000	$2,508,000
	Total	$2,000,000		$2,115,000	*Savings in IPP -	234,000	181,000
					Total	$2,541,000	$2,327,000
Capacity (TPD) 120 LH_2/600 LOX/300 LIN							
3 LH_2 cars		$ 750,000		$ 930,000			
2 LOX "		240,000		263,000			
2 LIN "		240,000		137,500			
7		1,230,000	Special train	1,330,500			
	Rail siding	400,000	charge -	334,000		$2,202,000	$1,985,000
	Total	$1,630,000		$1,664,500	*Savings in IPP -	189,000	143,000
					Total	$2,013,000	$1,842,000
Capacity (TPD) 40 LH_2/200 LOX/100 LIN							
1 LH_2 cars		$250,000		$309,000			
1 LOX "		120,000		88,000			
1 LIN "		120,000		45,800			
3		490,000	Special train	442,800			
	Rail siding	400,000	charge -	334,000		$1,071,000	$952,000
	Total	$890,000		$776,800	*Savings in IPP -	90,000	64,000
					Total	$ 981,000	$888,000

*Savings in IPP - Savings in Integrated Propellant Plant operating and investment cost due to reduced losses using this mode of transport in comparison to trucking.

(Note: See following page for Basis)

Figure 73 - continued

Basis:

1. 5 hour turnaround
2. 4 train trips per day
3. 7% losses
4. Special train charge \$430 per 10 hr. period
5. LH_2 car - capacity 11.8 tons, cost \$250,000
6. LOX car - capacity 90 tons, cost \$120,000

Figure 75

TABULATED SUMMARY OF BARGING COSTS - MTF BARGES

MTF Barge Requirements		Initial Investment (receiving facilities)	Annual Operating Cost, $/yr.		Total Annual Cost, $/yr. 5 yr Contract	15 yr Contract
Capacity (TPD) 160 LH_2/800 LOX/400 LIN						
2 LH_2 barges		$ 225,000	$ 519,000			
1 LOX barge		468,000	392,000			
1 LIN "		432,000	292,000		$1,706,000	$1,503,000
4		1,125,000	$1,203,000	*Savings in IPP-	234,000	181,000
	Dredging	400,000		Total	$1,472,000	$1,322,000
	Total	$1,525,000				
Capacity (TPD) 120 LH_2/600 LOX/300 LIN						
1 LH_2 barge		$ 225,000	$388,000			
1 LOX "		432,000	294,000			
1 LIN "		432,000	219,000		$1,392,000	$1,194,000
3		1,089,000	$901,000	*Savings in IPP-	189,000	143,000
	Dredging	400,000		Total	$1,203,000	$1,051,000
	Total	$1,489,000				
Capacity (TPD) 40 LH_2/200 LOX/100 LIN						
1 LH_2 barge		$ 207,000	$129,500			
1 LOX "		432,000	98,000			
1 LIN "		414,000	73,000		$780,000	$586,000
3		1,053,000	$300,500	*Savings in IPP-	90,000	64,000
	Dredging	400,000		Total	$690,000	$522,000
	Total	$1,453,000				

*Savings in IPP - Savings in Integrated Propellant Plant operating and investment cost due to reduced losses using this mode of transport in comparison to trucking.

Basis:
1. 10 hour turnaround
2. 7% losses
3. Tug cost $1,200 per day
4. 1,500 ft. LH_2 VIP, 3,000 ft. LOX, LIN VIP

Figure 76

TABULATED SUMMARY OF BARGING COSTS - NEW BARGES

Barge Requirements		Initial Investment	Annual Operating Cost, $/yr.		Total Annual Cost, $/yr. 5 yr Contract	Total Annual Cost, $/yr. 15 yr Contract
Capacity (TPD) 160 LH_2/800 LOX/400 LIN						
2 LH_2 barges		$2,025,000	$ 519,000			
1 LOX barge		1,068,000	392,000			
1 LIN "		1,032,000	292,000		$2,696,000	$2,093,000
4		4,125,000	$1,203,000	*Savings in IPP-	234,000	181,000
	Dredging	400,000		Total	$2,462,000	$1,912,000
	Total	$4,525,000				
Capacity (TPD) 120 LH_2/600 LOX/300 LIN						
1 LH_2 barge		$1,125,000	$ 388,000			
1 LOX "		1,032,000	294,000			
1 LIN "		1,032,000	219,000		$2,085,000	$1,607,000
3		3,189,000	$ 901,000	*Savings in IPP-	189,000	143,000
	Dredging	400,000		Total	$1,896,000	$1,464,000
	Total	$3,589,000				
Capacity (TPD) 40 LH_2/200 LOX/100 LIN						
1 LH_2 barge		$1,107,000	$ 129,500			
1 LOX "		1,032,000	98,000			
1 LIN "		1,014,000	73,000		$1,473,000	$999,000
3		3,153,000	$ 300,500	* Savings in IPP-	90,000	64,000
	Dredging	400,000		Total	$1,383,000	$935,000
	Total	$3,553,000				

*Savings in IPP - Savings in Integrated Propellant Plant operating and investment cost due to reduced losses using this mode of transport in comparison to trucking.

Basis:

1. 10 hour turnaround
2. 7% losses
3. Tug cost $1,200 per day
4. 1500 feet LH_2 VIP, 3,000 feet LOX, LIN VIP
5. LH_2 barge - capacity 72 tons, cost $900,000
6. LOX barge - capacity 475 tons, cost $600,000
7. LIN barge - capacity 64 tons, cost $600,000

Figure 77

TABULATED SUMMARY OF PIPELINE COSTS FROM NASA SITES #1 AND #2

Pipe Size	Initial Investment	Annual Operating Cost, $/yr.	Total Annual Cost, $/yr. 5 yr Contract	Total Annual Cost, $/yr. 15 yr Contract
Capacity (TPD) 160 LH_2/800 LOX/400 LIN				
3" LH_2	$3,000,000		$ 990,000	$ 590,000
4" LOX	2,808,000		927,000	552,000
3" LIN	2,592,000		855,000	510,000
	$8,400,000		2,772,000	1,652,000
		*Savings in IPP	702,000	542,000
		Total	$2,070,000	$1,110,000
Capacity (TPD) 120 LH_2/600 LOX/300 LIN				
3" LH_2	$3,000,000		$ 990,000	$ 590,000
3" LOX	2,592,000		855,000	510,000
3" LIN	2,592,000		855,000	510,000
	$8,184,000		2,700,000	1,610,000
		*Savings in IPP	566,000	430,000
		Total	$2,134,000	$1,180,000
Capacity (TPD) 40 LH_2/200 LOX/100 LIN				
2" LH_2	$2,760,000		$ 910,000	$ 543,000
3" LOX	2,592,000		855,000	510,000
2½" LIN	2,484,000		820,000	489,000
	$7,836,000		2,585,000	1,542,000
		*Savings in IPP	271,000	193,000
		Total	$2,314,000	$1,349,000

*Savings in IPP - Savings in Integrated Propellant Plant operating and investment cost due to reduced losses using this mode of transport in comparison to trucking.

Basis: 1. 20,000 ft. LH_2 piping, 18,000 ft. LOX, LIN pipe

2. 5% losses

Figure 78

TABULATED SUMMARY OF 5600 FT. PIPELINE COSTS FROM NASA SITE #3

Pipe Size	Initial Investment	Annual Operating Cost, \$/yr.	Total Annual Cost, \$/yr. 5 Yr. Contract	Total Annual Cost, \$/yr. 15 Yr. Contract
Capacity (TPD)				
160 LH_2/800 LOX/400 LIN				
3" LH_2	\$ 840,000		\$ 277,000	\$ 165,000
4" LOX	873,000		288,000	172,000
3" LIN	806,000		266,000	159,000
	\$ 2,519,000		831,000	496,000
		*Savings in IPP	702,000	542,000
		Total	\$ 129,000	\$ -46,000
Capacity (TPD)				
120 LH_2/600 LOX/300 LIN				
3" LH_2	\$ 840,000		\$ 277,000	\$ 165,000
3" LOX	806,000		266,000	159,000
3" LIN	806,000		266,000	159,000
	\$ 2,452,000		809,000	483,000
		*Savings in IPP	566,000	430,000
		Total	\$ 243,000	\$ 53,000
Capacity (TPD)				
40 LH_2/200 LOX/100 LIN				
2"	\$ 773,000		\$ 255,000	\$ 152,000
3"	806,000		266,000	159,000
2½"	773,000		255,000	152,000
	\$ 2,352,000		776,000	463,000
		*Savings in IPP	271,000	193,000
		Total	\$ 505,000	\$ 270,000

*Savings in IPP - Savings in Integrated Propellant Plant operating and investment cost due to reduced losses using this mode of transport in comparison to trucking.

Basis: 1. 5,600 ft. LH_2, LOX, LIN VIP

2. 5% losses

Figure 82

TABULATED SUMMARY OF NASA SITE #1 COSTS

	Initial Investment	Annual Cost, \$/yr.	Total Annual Cost, \$/yr. 5 Yr. Contract	Total Annual Cost, \$/yr. 15 Yr. Contract
160 TPD LH_2, 800 TPD LOX, 400 TPD LIN				
Site Premium	\$ 300,000		\$ 99,000	\$ 59,000
Feed Transport	562,000	\$ 483,000	668,000	594,000
*Product Transport	(see Fig. 72 & 77)		1,795,000	1,110,000
Total			\$2,652,000	\$1,763,000
120 TPD LH_2, 600 TPD LOX, 300 TPD LIN				
Site Premium	\$ 300,000		\$ 99,000	\$ 59,000
Feed Transport	530,000	\$ 362,000	537.000	466,000
*Product Transport	(see Fig. 72 & 77)		1,723,000	1,069,000
Total			\$2,359,000	\$1,594,000
40 TPD LH_2, 200 TPD LOX, 100 TPD LIN				
Site Premium	\$ 300,000		\$ 99,000	\$ 59,000
Feed Transport	249,000	\$ 121,000	203,000	170,000
Product Transport (Truck)	(see Fig. 72)		770,000	657,000
Total			\$1,072,000	\$886,000

*Product Transport - VIP LOX, LH_2 truck LIN for 5-year contract, VIP for 15-year contract.

Figure 83

TABULATED SUMMARY OF NASA SITE #2 COSTS

	Initial Investment	Annual Cost	Total Annual Cost: 5 Yr. Contract	Total Annual Cost: 15 Yr. Contract
160 TPD LH_2, 800 TPD LOX, 400 TPD LIN				
Site Premium	\$-100,000		\$ -33,000	\$ -20,000
Feed Transport	562,000	\$483,000	668,000	594,000
*Product Transport	(see Fig. 72 & 77)		1,795,000	1,110,000
Total			\$2,430,000	\$1,684,000
120 TPD LH_2, 600 TPD LOX, 300 TPD LIN				
Site Premium	\$-100,000		\$ -33,000	\$ -20,000
Feed Transport	530,000	\$362,000	537,000	466,000
*Product Transport	(see Fig. 72 & 77)		1,723,000	1,069,000
Total			\$2,227,000	\$1,515,000
40 TPD LH_2, 200 TPD LOX, 100 TPD LIN				
Site Premium	\$-100,000		\$ -33,000	\$-20,000
Feed Transport	249,000	\$121,000	203,000	170,000
Product Transport(Truck)	(see Fig. 72)		770,000	657,000
Total			\$ 940,000	\$807,000

*Product Transport - VIP LH_2, LOX and truck LIN for 5-year contract, VIP for 15-year contract.

Figure 84

TABULATED SUMMARY OF NASA SITE #3 COSTS

	Initial Investment	Annual Cost, \$/yr.	Total Annual Cost, \$/yr. 5 Yr. Contract	Total Annual Cost, \$/yr. 15 Yr. Contract
160 TPD LH_2, 800 TPD LOX, 400 TPD LIN				
Site Premium	\$1,750,000		\$ 578,000	\$ 344,000
Feed Transport	562,000	\$483,000	668,000	594,000
Product Transport(VIP)	(see Fig. 77)		129,000	-47,000
Total			\$1,375,000	\$ 891,000
120 TPD LH_2, 600 TPD LOX, 300 TPD LIN				
Site Premium	\$1,750,000		\$ 578,000	\$ 344,000
Feed Transport	530,000	\$362,000	537,000	466,000
Product Transport(VIP)	(see Fig. 77)		243,000	53,000
Total			\$1,358,000	\$ 863,000
40 TPD LH_2, 200 TPD LOX, 100 TPD LIN				
Site Premium	\$1,750,000		\$ 578,000	\$ 344,000
Feed Transport	249,000	\$121,000	203,000	170,000
Product Transport(VIP)	(see Fig. 77)		505,000	270,000
Total			\$1,286,000	\$ 784,000

Figure 85

TABULATED SUMMARY OF PORT CANAVERAL SITE COSTS

	Initial Investment	Annual Cost, \$/yr.	Total Annual Cost, \$/yr. 5 Yr. Contract	Total Annual Cost, \$/yr. 15 Yr. Contract
160 TPD LH_2, 800 TPD LOX, 400 TPD LIN				
Site Premium	\$ 600,000		\$ 198,000	\$ 118,000
Feed Transport	-	-	-	-
Product Transport (MTF Barges)	(see Fig. 76)		1,472,000	1,322,000
Total			\$ 1,670,000	\$ 1,440,000
120 TPD LH_2, 600 TPD LOX, 300 TPD LIN				
Site Premium	\$ 600,000		\$ 198,000	\$ 118,000
Feed Transport	-	-	-	-
Product Transport (MTF Barges)	(see Fig. 76)		1,203,000	1,051,000
Total			\$ 1,401,000	\$ 1,169,000
40 TPD LH_2, 200 TPD LOX, 100 TPD LIN				
Site Premium	\$ 600,000		\$ 198,000	\$ 118,000
Feed Transport	-	-	-	-
Product Transport (MTF Barges)	(see Fig. 76)		690,000	522,000
Total			\$ 888,000	\$ 640,000

Figure 86

TABULATED SUMMARY OF FLORIDA EAST COAST SITE COSTS

	Initial Investment	Annual Cost, \$/yr.	Total Annual Cost, \$/yr. 5 Yr. Contract	Total Annual Cost, \$/yr. 15 Yr. Contract
160 TPD LH_2, 800 TPD LOX, 400 TPD LIN				
Site Premium	\$200,000		\$ 66,000	\$ 40,000
Feed Transport	562,000	\$ 483,000	668,000	594,000
Product Transport (Rail)	(see Fig. 73)		2,541,000	2,327,000
Total			\$3,275,000	\$2,961,000
120 TPD LH_2, 600 TPD LOX, 300 TPD LIN				
Site Premium	\$200,000		\$ 66,000	\$ 40,000
Feed Transport	530,000	\$ 362,000	537,000	466,000
Product Transport (Rail)	(see Fig. 73)		2,013,000	1,842,000
Total			\$2,616,000	\$2,348,000
40 TPD LH_2, 200 TPD LOX, 100 TPD LIN				
Site Premium	\$200,000		\$ 66,000	\$ 40,000
Feed Transport	249,000	\$ 121,000	203,000	170,000
Product Transport (Rail)	(see Fig. 73)		770,000	657,000
Total			\$1,039,000	\$867,000

Figure 89

MINIMUM REQUIREMENTS OPTION

QUARTERLY LOAD PATTERNS & USE POINTS 1970 - 1976

TONS/DAY LH_2

		MTF	MSFC	KSC	TOTAL EAST	TOTAL WEST
1970	1	-	-	10.19	10.19	27.59
	2	-	-	10.19	10.19	27.59
	3	-	-	10.19	10.19	27.59
	4	-	-	10.68	10.68	28.09
1971	1	-	-	9.75	9.75	34.50
	2	12.23	3.06	9.75	25.04	35.13
	3	12.23	3.06	9.75	25.04	35.87
	4	12.23	3.06	9.75	25.04	36.17
1972	1	12.23	3.06	9.37	24.66	26.54
	2	12.23	3.06	9.37	24.66	27.16
	3	42.28	10.60	9.38	62.26	27.41
	4	42.35	10.62	9.40	62.37	28.27
1973	1	18.76	4.97	8.86	32.59	37.04
	2	9.73	2.83	8.90	21.46	37.28
	3	9.97	3.07	8.91	21.95	37.04
	4	10.46	3.57	8.91	22.94	36.67
1974	1	10.68	3.78	8.52	22.98	40.92
	2	11.52	4.61	8.51	24.64	40.31
	3	11.52	4.61	8.51	24.64	40.37
	4	11.52	4.61	8.51	24.64	41.30
1975	1	24.56	7.88	11.39	43.83	55.87
	2	24.56	7.88	11.39	43.83	54.67
	3	24.56	7.88	11.39	43.83	53.15
	4	24.31	7.63	11.39	43.33	50.99
1976	1	4.14	2.58	14.38	21.10	21.36
	2	4.14	2.27	14.39	20.79	21.48
	3	4.14	1.29	14.38	19.81	21.36
	4	4.14	1.10	14.38	19.62	21.36

Figure 89 (cont.)
MINIMUM REQUIREMENTS OPTION

LOAD PATTERNS & USE POINTS 1977 - 1985

TONS/DAY LH_2

	MTF	MSFC	KSC	TOTAL EAST	TOTAL WEST
1977	4.51	4.51	21.35	30.37	14.38
1978	3.09	3.09	53.05	59.23	5.12
1979	3.09	3.09	112.27	118.45	5.12
1980	3.09	3.09	156.54	162.72	5.12
1981	2.35	2.35	189.28	193.98	5.12
1982	2.35	2.35	113.28	117.99	5.12
1983	1.85	1.85	193.70	197.40	5.12
1984	0.75	0.75	136.00	137.50	5.12
1985	0.43	0.43	134.62	135.48	5.12

Figure 90

MINIMUM REQUIREMENTS OPTION

TABULATED SOLUTION DESCRIPTION

Solution No.	III	IV
Case No.	12,13	44,45
Plant Data		
Michoud:		
Size	E-30 T/D	E-30 T/D
Years Operated	70-77 81,83	70-76 78,81,83
KSC:		
Size	N-170 T/D	RWC - 30 T/D
Years Operated	78-85	80,81,83
Size		N - 140 T/D
Years Operated		79-85

Legend: E = Existing
RWC = Relocated West Coast
N = New

Note: Solution Nos. and Case No. are from Table C-4 NASA Contract NAS8-25147, March 1970

Figure 91

MINIMUM REQUIREMENTS OPTION

TABULATED CASE DESCRIPTIONS

CASE	5	7	20	22	24	26	8	21	50
Solution	III	III	III	III	III	III	III	III	IV
Program Cost MM$	224.19	219.11	217.86	230.27	219.48	222.93	330.0	326.5	227.07
LH_2 Cost, ¢/lb	25.80	25.21	25.07	26.50	25.26	25.65	38.98	37.58	26.13
Plant Type	IPP	IPP	IPP	LH_2	IPP	IPP	IPP	IPP	IPP
Process	REF	REF	REF	REF	REF	PO	REF	REF	REF
Drive System	ELEC	ELEC	GT	ELEC	ST	GT	ELEC	GT	ELEC
Fuel	-	-	Fuel Oil 45¢	-	Fuel Oil 45¢	Fuel Oil 45¢	-	Fuel Oil 45¢	-
Feed	55¢ NAP	55¢ NAP	55¢ NAP	55¢ NAP	55¢ NAP	Fuel Oil 45¢	55¢ NAP	55¢ NAP	55¢ NAP
Power	6 mil	5 mil	6 mil	6 mil	6 mil	6 mil	5 mil	6 mil	6 mil
Escalation	1.0	1.0	1.0	1.0	1.0	1.0	1.05	1.05	1.0

Legend:
IPP - Integrated Propellant Plant
REF - Steam Reforming
PO - Partial Oxidation
ST - Steam Turbine
GT - Gas Turbine
ELEC - Electric Motor
NAP - Naptha

LH_2 - Liquid Hydrogen

Figure 92

50 LAUNCH OPTION

TABULATED LOAD PATTERNS 1970 - 1985

TONS/DAY LH_2

Year	MTF	MSFC	KSC	Total East	Total West
1970	0	0	5.1	5.1	13.8
1971	6.0	2.0	4.9	12.9	17.5
1972	13.6	3.0	4.7	21.3	14.0
1973	6.1	2.0	4.4	12.7	18.5
1974	5.7	2.2	4.2	12.1	20.4
1975	12.2	4.0	5.7	21.9	26.8
1976	2.1	0.9	7.2	10.2	10.7
1977	2.3	2.3	3.6	8.2	7.2
1978	1.5	1.5	10.0	13.0	2.6
1979	1.5	1.5	20.0	23.0	2.6
1980	1.5	1.5	35.0	38.0	2.6
1981	1.2	1.2	60.0	62.4	2.6
1982	1.2	1.2	60.0	62.4	2.6
1983	1.0	1.0	60.0	62.0	2.6
1984	0.4	0.4	60.0	60.8	2.6
1985	0.2	0.2	60.0	60.4	2.6

Figure 93

50 LAUNCH OPTION

TABULATED CASE DESCRIPTIONS

CASE	70	71	75
Program Cost MM$	97.47	150.79	99.23
LH_2 Cost, ¢/lb	30.94	47.86	31.49
Type Plant	R-LSH 1980	R-LSH 1980	60 TPD IPP 1980
APCI Michoud Running	1970-1980	1970-1980	1970-1980
West Coast Shipping	1981-1985	1981-1985	1981-1985
Escalation	1.0	1.05	1.0

Legend:

R-LSH = Relocate Sacramento 60 TPD

IPP = Integrated Propellant Plant

Figure 94

REVISED MINIMUM REQUIREMENTS OPTION

LH_2 REQUIREMENTS, TONS PER DAY

	MTF	MSFC	KSC	Total East	Total West
1971	0	3.646	3.998	7.644	11.97
2	0	3.776	1.351	5.127	11.97
3	0	3.776	5.047	8.823	12.118
4	0	3.776	1.623	5.399	12.241
1972	0	6.349	4.782	11.131	13.623
2	0	11.310	10.672	21.982	19.497
3	0	12.544	13.247	25.791	21.225
4	0	13.161	16.394	29.555	21.533
1973	0	13.766	18.22	31.986	30.653
2	0	14.383	16.178	30.561	28.876
3	0	15.617	13.105	28.722	21.472
4	0	16.851	11.523	28.374	21.657
1974	0	18.085	12.963	31.048	26.346
2	0	18.702	9.582	28.284	26.469
3	0	19.319	9.236	28.555	24.495
4	0	21.17	13.994	35.164	22.952
1975	0	3.894	12.815	16.709	32.331
2	4.627	3.894	12.395	20.916	32.331
3	9.317	3.894	11.019	24.230	32.392
4	18.51	3.894	46.164	68.568	32.392
1976	23.261	3.894	48.146	75.301	20.114
2	23.261	3.894	46.456	73.611	20.114
3	13.882	3.894	47.714	65.490	19.991
4	0	3.894	5.473	9.367	24.865
1977	0	3.894	5.473	9.367	14.07
1978	0	3.894	16.270	20.164	9.44
1979	0	3.894	18.654	22.548	0.185
1980	0	3.894	26.63	30.524	0.185
1981	0	3.894	32.8	36.694	0.185
1982	0	3.894	43.597	47.491	0.185
1983	0	3.894	54.395	58.289	0.185
1984	0	3.894	65.192	69.086	0.185
1985	0	3.894	75.99	79.884	0.185
1986	0	3.894	84.473	88.367	0.185

Figure 95

REVISED MINIMUM REQUIREMENTS OPTION

TABULATED CASE DESCRIPTIONS

Case	81	85	83	84	86	88
Program Cost, MM$	154.66	134.49	129.98	186.73	131.58	136.84
LH_2 Cost, ¢/lb.	37.27	32.41	31.32	45.00	31.71	32.98
Type Plant	R-LSH 1981 - 1	R-LSH 1973 - 1	R-LSH 1975 - 4	R-LSH 1975 - 4	IPP - 60 TPD 1975 - 4	IPP - 90 TPD 1975 - 4
APCI Running	1971-1981, 1984-1986	1971-1975, 1975-4-1976-3, 1984-1986	1971-1976-3, 1984-1986	1971-1976-3, 1984-1986	1971-1976-3, 1984-1986	1971-1975-4
Escalation	1.0	1.0	1.0	1.05	1.0	1.0

Legend: R-LSH = Relocate Sacramento 60 TPD

IPP = Integrated Propellant Plant

Number following the years listed indicates the quarter of that year.

APPENDIX B

COMPUTER SOLUTIONS TO THE MINIMUM REQUIREMENTS OPTION

EAST COAST LIQUID HYDROGEN COSTS

MINIMUM REQUIREMENTS OPTION CASE NO. 7
TABLE 1

ESC 1.00000 NEW PLANTS: 1978 1 KSC 170 T/D

YEAR	ANNUAL USAGE MM#	ANNUAL PRODUCTION MM$	ANNUAL PRODUCTION C/#	ANNUAL TRANSPORTATION MM$	ANNUAL TRANSPORTATION C/#	ANNUAL TOTAL MM$	ANNUAL TOTAL C/#	CUMULATIVE USAGE MM#	CUMULATIVE PRODUCTION MM$	CUMULATIVE PRODUCTION C/#	CUMULATIVE TRANSPORTATION MM$	CUMULATIVE TRANSPORTATION C/#	CUMULATIVE TOTAL MM$	CUMULATIVE TOTAL C/#
1970	6.6822	2.3335	34.9211	.8336	12.4749	3.1671	47.3960	6.6822	2.3335	34.9211	.8336	12.4749	3.1671	47.3960
1971	13.7487	2.8993	21.0878	.9067	11.6167	3.8060	27.6826	20.4309	5.2328	25.6121	1.7403	12.0125	6.9731	34.1301
1972	28.1755	5.5709	19.7693	6.7127	46.3037	12.2836	43.5905	48.6104	10.8037	22.2250	8.4530	29.1639	19.2567	39.6143
1973	16.0278	3.1423	19.6053	2.2778	28.1109	5.4201	33.8168	64.6382	13.9460	21.5754	10.7308	28.9338	24.6768	38.1768
1974	15.6974	3.0549	19.4611	2.1022	25.1197	5.1571	32.8532	80.3356	17.0009	21.1623	12.8330	28.2316	29.8339	37.1365
1975	28.3202	5.3518	18.8974	6.4707	51.9906	11.8225	41.7458	108.6558	22.3527	20.5720	19.3037	33.3386	41.6564	38.3379
1976	13.1747	2.8534	21.6581	2.4447	23.2999	5.2981	40.2141	121.8305	25.2061	20.6894	21.7484	31.7986	46.9545	38.5408
1977	19.6792	3.4076	17.3157	2.7211	16.2387	6.1287	31.1430	141.5097	28.6137	20.2203	24.4695	28.7365	53.0832	37.5120
1978	38.3804	16.8156	43.8129	.5108	12.7572	17.3264	45.1438	179.8901	45.4293	25.2539	24.9803	28.0189	70.4096	39.1403
1979	76.7548	20.5916	26.8277	.5108	12.7572	21.1024	27.4932	256.6449	66.0209	25.7246	25.4911	27.3630	91.5120	35.6570
1980	105.4416	23.4144	22.2060	.5108	12.7572	23.9252	22.6904	362.0865	89.4353	24.6999	26.0019	26.7611	115.4372	31.8811
1981	125.6988	26.9220	21.4178	1.7500	12.4857	28.6720	22.8100	487.7853	116.3573	23.8542	27.7519	24.9614	144.1092	29.5435
1982	76.4508	20.5616	26.8952	.3880	12.7396	20.9496	27.4027	564.2361	136.9189	24.2662	28.1399	24.6355	165.0588	29.2534
1983	127.9152	20.8184	16.2751	2.1250	12.8349	22.9434	17.9364	692.1513	157.7373	22.7894	30.2649	23.1416	188.0022	27.1620
1984	89.1000	15.5260	17.4253	.1224	12.5925	15.6484	17.5627	781.2513	173.2633	22.1776	30.3873	23.0638	203.6506	26.0672
1985	87.7904	15.3972	17.5385	.0696	12.5000	15.4668	17.6178	869.0417	188.6605	21.7090	30.4569	23.0193	219.1174	25.2136

EAST COAST LIQUID HYDROGEN COSTS

MINIMUM REQUIREMENTS OPTION CASE NO. 8
TABLE 1

ESC 1.05000 NEW PLANTS: 1978 1 KSC 170 T/D

YEAR	ANNUAL USAGE MM#	ANNUAL PRODUCTION MM$	ANNUAL PRODUCTION C/#	ANNUAL TRANSPORTATION MM$	ANNUAL TRANSPORTATION C/#	ANNUAL TOTAL MM$	ANNUAL TOTAL C/#	CUMULATIVE USAGE MM#	CUMULATIVE PRODUCTION MM$	CUMULATIVE PRODUCTION C/#	CUMULATIVE TRANSPORTATION MM$	CUMULATIVE TRANSPORTATION C/#	CUMULATIVE TOTAL MM$	CUMULATIVE TOTAL C/#
1970	6.6822	2.3435	35.0707	.8492	12.7083	3.1927	47.7791	6.6822	2.3435	35.0707	.8492	12.7083	3.1927	47.7791
1971	13.7487	2.9793	21.6696	.9706	12.4354	3.9499	28.7292	20.4309	5.3228	26.0526	1.8198	12.5613	7.1426	34.9597
1972	28.1795	6.0685	21.5351	7.5489	52.0717	13.6174	48.3237	48.6104	11.3913	23.4338	9.3687	32.3232	20.7600	42.7069
1973	16.0278	3.3786	21.0796	2.5598	31.5911	5.9384	37.0506	64.6382	14.7699	22.8501	11.9285	32.1633	26.6984	41.3043
1974	15.6974	3.3543	21.3685	2.4115	28.8157	5.7658	36.7309	80.3356	18.1242	22.5606	14.3400	31.5469	32.4642	40.4107
1975	28.3202	6.4172	22.6594	8.1461	65.4520	14.5633	51.4237	108.6558	24.5414	22.5863	22.4861	38.8348	47.0275	43.2811
1976	13.1747	3.2376	24.5743	2.9944	28.5390	6.2320	47.3027	121.8305	27.7790	22.8013	25.4805	37.2553	53.2595	43.7160
1977	19.6792	4.1048	20.8585	3.6643	21.8675	7.7691	39.4787	141.5097	31.8838	22.5311	29.1448	34.2271	61.0286	43.1267
1978	38.3804	24.0539	62.6723	.7694	19.2157	24.8233	64.6770	179.8901	55.9377	31.0954	29.9142	33.5530	85.8519	47.7246
1979	76.7548	30.4656	39.6921	.8080	20.1798	31.2736	40.7448	256.6449	86.4033	33.6664	30.7222	32.9782	117.1255	45.6371
1980	105.4416	35.9149	34.0614	.8483	21.1863	36.7632	34.8659	362.0865	122.3182	33.7814	31.5705	32.4923	153.8887	42.5005
1981	125.6988	41.7269	33.1959	3.0010	21.4112	44.7279	35.5833	487.7853	164.0451	33.6305	34.5715	31.0953	198.6166	40.7180
1982	76.4508	32.8245	42.9354	.7110	23.3451	33.5355	43.8654	564.2361	196.8696	34.8913	35.2825	30.8887	232.1521	41.1444
1983	127.9152	35.8766	28.0471	3.9826	24.0547	39.8592	31.1606	692.1513	232.7462	33.6264	39.2651	30.0235	272.0113	39.2993
1984	89.1000	28.4166	31.8929	.2500	25.7201	28.6666	32.1735	781.2513	261.1628	33.4287	39.5151	29.9918	300.6779	38.4867
1985	87.7904	29.2438	33.3109	.1490	26.7600	29.3928	33.4806	869.0417	290.4066	33.4168	39.6641	29.9782	330.0707	37.9809

EAST COAST LIQUID HYDROGEN COSTS

MINIMUM REQUIREMENTS OPTION CASE NO. 20

TABLE 1

ESC 1.00000 NEW PLANTS: 1978 1 KSC 170 T/D

YEAR	USAGE	PRODUCTION		TRANSPORTATION		TOTAL	ANNUAL	CUMULATIVE USAGE	PRODUCTION		TRANSPORTATION		TOTAL	
	MM#	MM$	C/#	MM$	C/#	MM$	C/#	MM#	MM$	C/#	MM$	C/#	MM$	C/#
1970	6.6822	2.3335	34.9211	.8336	12.4749	3.1671	47.3960	6.6822	2.3335	34.9211	.8336	12.4749	3.1671	47.3960
1971	13.7487	2.8993	21.0878	.9067	11.6167	3.8060	27.6826	20.4309	5.2328	25.6121	1.7403	12.0125	6.9731	34.1301
1972	28.1795	5.5709	19.7693	6.7127	46.3037	12.2836	43.5905	48.6104	10.8037	22.2250	8.4530	29.1639	19.2567	39.6143
1973	16.0278	3.1423	19.6053	2.2778	28.1109	5.4201	33.8168	64.6382	13.9460	21.5754	10.7308	28.9338	24.6768	38.1768
1974	15.6974	3.0549	19.4611	2.1022	25.1197	5.1571	32.8532	80.3356	17.0009	21.1623	12.8330	28.2316	29.8339	37.1365
1975	28.3202	5.3518	18.8974	6.4707	51.9906	11.8225	41.7458	108.6558	22.3527	20.5720	19.3037	33.3386	41.6564	38.3379
1976	13.1747	2.8534	21.6581	2.4447	23.2999	5.2981	40.2141	121.8305	25.2061	20.6894	21.7484	31.7986	46.9545	38.5408
1977	19.6792	3.4076	17.3157	2.7211	16.2387	6.1287	31.1430	141.5097	28.6137	20.2203	24.4695	28.7365	53.0832	37.5120
1978	38.3804	17.2204	44.8676	.5108	12.7572	17.7312	46.1985	179.8901	45.8341	25.4789	24.9803	28.0189	70.8144	39.3653
1979	76.7548	20.7204	26.9955	.5108	12.7572	21.2312	27.6610	256.6449	66.5545	25.9325	25.4911	27.3630	92.0456	35.8649
1980	105.4416	23.3364	22.1320	.5108	12.7572	23.8472	22.6165	362.0865	89.8909	24.8258	26.0019	26.7611	115.8928	32.0069
1981	125.6988	26.8100	21.3287	1.7500	12.4857	28.5600	22.7209	487.7853	116.7009	23.9246	27.7519	24.9614	144.4528	29.6140
1982	76.4508	20.6928	27.0668	.3880	12.7396	21.0808	27.5743	564.2361	137.3937	24.3503	28.1399	24.6355	165.5336	29.3376
1983	127.9152	20.1372	15.7426	2.1250	12.8349	22.2622	17.4038	692.1513	157.5309	22.7596	30.2649	23.1416	187.7958	27.1321
1984	89.1000	14.9964	16.8309	.1224	12.5925	15.1188	16.9683	781.2513	172.5273	22.0834	30.3873	23.0638	202.9146	25.9730
1985	87.7904	14.8772	16.9462	.0696	12.5000	14.9468	17.0255	869.0417	187.4045	21.5645	30.4569	23.0193	217.8614	25.0691

EAST COAST LIQUID HYDROGEN COSTS

MINIMUM REQUIREMENTS OPTION CASE NO. 21

TABLE 1

ESC 1.05000 NEW PLANTS: 1978 1 KSC 170 T/D

YEAR	USAGE	PRODUCTION		TRANSPORTATION		TOTAL	ANNUAL	CUMULATIVE USAGE	PRODUCTION		TRANSPORTATION		TOTAL	
	MM#	MM$	C/#	MM$	C/#	MM$	C/#	MM#	MM$	C/#	MM$	C/#	MM$	C/#
1970	6.6822	2.3435	35.0707	.8492	12.7083	3.1927	47.7791	6.6822	2.3435	35.0707	.8492	12.7083	3.1927	47.7791
1971	13.7487	2.9793	21.6696	.9706	12.4354	3.9499	28.7292	20.4309	5.3228	26.0526	1.8198	12.5613	7.1426	34.9597
1972	28.1795	6.0685	21.5351	7.5489	52.0717	13.6174	48.3237	48.6104	11.3913	23.4338	9.3687	32.3232	20.7600	42.7069
1973	16.0278	3.3786	21.0796	2.5598	31.5911	5.9384	37.0506	64.6382	14.7699	22.8501	11.9285	32.1633	26.6984	41.3043
1974	15.6974	3.3543	21.3685	2.4115	28.8157	5.7658	36.7309	80.3356	18.1242	22.5606	14.3400	31.5469	32.4642	40.4107
1975	28.3202	6.4172	22.6594	8.1461	65.4520	14.5633	51.4237	108.6558	24.5414	22.5863	22.4861	38.8348	47.0275	43.2811
1976	13.1747	3.2376	24.5743	2.9944	28.5390	6.2320	47.3027	121.8305	27.7790	22.8013	25.4805	37.2553	53.2595	43.7160
1977	19.6792	4.1048	20.8585	3.6643	21.8675	7.7691	39.4787	141.5097	31.8838	22.5311	29.1448	34.2271	61.0286	43.1267
1978	38.3804	24.5978	64.0894	.7694	19.2157	25.3672	66.0941	179.8901	56.4816	31.3978	29.9142	33.5530	86.3958	48.0269
1979	76.7548	30.5605	39.8157	.8080	20.1798	31.3685	40.8684	256.6449	87.0421	33.9153	30.7222	32.9782	117.7643	45.8860
1980	105.4416	35.6318	33.7929	.8483	21.1863	36.4801	34.5974	362.0865	122.6739	33.8797	31.5705	32.4923	154.2444	42.5987
1981	125.6988	41.3314	32.8813	3.0010	21.4112	44.3324	35.2687	487.7853	164.0053	33.6224	34.5715	31.0953	198.5768	40.7098
1982	76.4508	32.8140	42.9217	.7110	23.3451	33.5250	43.8517	564.2361	196.8193	34.8824	35.2825	30.8887	232.1018	41.1355
1983	127.9152	34.5687	27.0247	3.9826	24.0547	38.5513	30.1381	692.1513	231.3880	33.4302	39.2651	30.0235	270.6531	39.1031
1984	89.1000	27.3418	30.6945	.2500	25.7201	27.5988	30.9750	781.2513	258.7368	33.1182	39.5151	29.9918	298.2519	38.1761
1985	87.7904	28.1423	32.0562	.1490	26.7600	28.2913	32.2259	869.0417	286.8791	33.0109	39.6641	29.9782	326.5432	37.5750

EAST COAST LIQUID HYDROGEN COSTS

MINIMUM REQUIREMENTS OPTION CASE NO. 5

TABLE 1

ESC 1.00000 NEW PLANTS: 1978 1 KSC 170 T/D

YEAR	USAGE MM#	PRODUCTION MM$	PRODUCTION C/#	TRANSPORTATION MM$	TRANSPORTATION C/#	TOTAL MM$	ANNUAL C/#	CUMULATIVE USAGE MM#	PRODUCTION MM$	PRODUCTION C/#	TRANSPORTATION MM$	TRANSPORTATION C/#	TOTAL MM$	C/#
1970	6.6822	2.3335	34.9211	.8336	12.4749	3.1671	47.3960	6.6822	2.3335	34.9211	.8336	12.4749	3.1671	47.3960
1971	13.7487	2.8993	21.0878	.9067	11.6167	3.8060	27.6826	20.4309	5.2328	25.6121	1.7403	12.0125	6.9731	34.1301
1972	28.1795	5.5709	19.7693	6.7127	46.3037	12.2836	43.5905	48.6104	10.8037	22.2250	8.4530	29.1639	19.2567	39.6143
1973	16.0278	3.1423	19.6053	2.2778	28.1109	5.4201	33.8168	64.6382	13.9460	21.5754	10.7308	28.9338	24.6768	38.1768
1974	15.6974	3.0549	19.4611	2.1022	25.1197	5.1571	32.8532	80.3356	17.0009	21.1623	12.8330	28.2316	29.8339	37.1365
1975	28.3202	5.3518	18.8974	6.4707	51.9906	11.8225	41.7458	108.6558	22.3527	20.5720	19.3037	33.3386	41.6564	38.3379
1976	13.1747	2.8534	21.6581	2.4447	23.2999	5.2981	40.2141	121.8305	25.2061	20.6894	21.7484	31.7986	46.9545	38.5408
1977	19.6792	3.4076	17.3157	2.7211	16.2387	6.1287	31.1430	141.5097	28.6137	20.2203	24.4695	28.7365	53.0832	37.5120
1978	38.3804	17.0960	44.5435	.5108	12.7572	17.6068	45.8744	179.8901	45.7097	25.4097	24.9803	28.0189	70.6900	39.2962
1979	76.7548	21.1524	27.5584	.5108	12.7572	21.6632	28.2239	256.6449	66.8621	26.0523	25.4911	27.3630	92.3532	35.9848
1980	105.4416	24.1844	22.9362	.5108	12.7572	24.6952	23.4207	362.0865	91.0465	25.1449	26.0019	26.7611	117.0484	32.3260
1981	125.6988	27.7260	22.0574	1.7500	12.4857	29.4760	23.4497	487.7853	118.7725	24.3493	27.7519	24.9614	146.5244	30.0387
1982	76.4508	21.1200	27.6256	.3880	12.7396	21.5080	28.1331	564.2361	139.8925	24.7932	28.1399	24.6355	168.0324	29.7805
1983	127.9152	21.6224	16.9036	2.1250	12.8349	23.7474	18.5649	692.1513	161.5149	23.3352	30.2649	23.1416	191.7798	27.7077
1984	89.1000	16.1764	18.1553	.1224	12.5925	16.2988	18.2927	781.2513	177.6913	22.7444	30.3873	23.0638	208.0786	26.6340
1985	87.7904	16.0380	18.2685	.0696	12.5000	16.1076	18.3477	869.0417	193.7293	22.2922	30.4569	23.0193	224.1862	25.7969

EAST COAST LIQUID HYDROGEN COSTS

MINIMUM REQUIREMENTS OPTION CASE NO. 22

TABLE 1

ESC 1.00000 NEW PLANTS: 1978 1 KSC 170 T/D

YEAR	USAGE MM#	PRODUCTION MM$	PRODUCTION C/#	TRANSPORTATION MM$	TRANSPORTATION C/#	TOTAL MM$	ANNUAL C/#	CUMULATIVE USAGE MM#	PRODUCTION MM$	PRODUCTION C/#	TRANSPORTATION MM$	TRANSPORTATION C/#	TOTAL MM$	C/#
1970	6.6822	2.3335	34.9211	.8336	12.4749	3.1671	47.3960	6.6822	2.3335	34.9211	.8336	12.4749	3.1671	47.3960
1971	13.7487	2.8993	21.0878	.9067	11.6167	3.8060	27.6826	20.4309	5.2328	25.6121	1.7403	12.0125	6.9731	34.1301
1972	28.1795	5.5709	19.7693	6.7127	46.3037	12.2836	43.5905	48.6104	10.8037	22.2250	8.4530	29.1639	19.2567	39.6143
1973	16.0278	3.1423	19.6053	2.2778	28.1109	5.4201	33.8168	64.6382	13.9460	21.5754	10.7308	28.9338	24.6768	38.1768
1974	15.6974	3.0549	19.4611	2.1022	25.1197	5.1571	32.8532	80.3356	17.0009	21.1623	12.8330	28.2316	29.8339	37.1365
1975	28.3202	5.3518	18.8974	6.4707	51.9906	11.8225	41.7458	108.6558	22.3527	20.5720	19.3037	33.3386	41.6564	38.3379
1976	13.1747	2.8534	21.6581	2.4447	23.2999	5.2981	40.2141	121.8305	25.2061	20.6894	21.7484	31.7986	46.9545	38.5408
1977	19.6792	3.4076	17.3157	2.7211	16.2387	6.1287	31.1430	141.5097	28.6137	20.2203	24.4695	28.7365	53.0832	37.5120
1978	38.3804	18.1076	47.1792	.5108	12.7572	18.6184	48.5101	179.8901	46.7213	25.9721	24.9803	28.0189	71.7016	39.8585
1979	76.7548	22.2060	28.9310	.5108	12.7572	22.7168	29.5965	256.6449	68.9273	26.8570	25.4911	27.3630	94.4184	36.7895
1980	105.4416	25.2696	23.9654	.5108	12.7572	25.7804	24.4499	362.0865	94.1969	26.0150	26.0019	26.7611	120.1988	33.1961
1981	125.6988	28.8169	22.9252	1.7500	12.4857	30.5668	24.3174	487.7853	123.0137	25.2188	27.7519	24.9614	150.7656	30.9081
1982	76.4508	22.1736	29.0037	.3880	12.7396	22.5616	29.5112	564.2361	145.1873	25.7316	28.1399	24.6355	173.3272	30.7189
1983	127.9152	21.9028	17.1229	2.1250	12.8349	24.0278	18.7841	692.1513	167.0901	24.1406	30.2649	23.1416	197.3550	28.5132
1984	89.1000	16.4336	18.4439	.1224	12.5925	16.5560	18.5813	781.2513	183.5237	23.4909	30.3873	23.0638	213.9110	27.3805
1985	87.7904	16.2940	18.5601	.0696	12.5000	16.3636	18.6393	869.0417	199.8177	22.9928	30.4569	23.0193	230.2746	26.4975

EAST COAST LIQUID HYDROGEN COSTS

MINIMUM REQUIREMENTS OPTION CASE NO. 24
TABLE 1

ESC 1.00000 NEW PLANTS: 1978 1 KSC 170 T/D

YEAR	ANNUAL USAGE MM#	ANNUAL PRODUCTION MM$	ANNUAL PRODUCTION C/#	ANNUAL TRANSPORTATION MM$	ANNUAL TRANSPORTATION C/#	ANNUAL TOTAL MM$	ANNUAL TOTAL C/#	CUMULATIVE USAGE MM#	CUMULATIVE PRODUCTION MM$	CUMULATIVE PRODUCTION C/#	CUMULATIVE TRANSPORTATION MM$	CUMULATIVE TRANSPORTATION C/#	CUMULATIVE TOTAL MM$	CUMULATIVE TOTAL C/#
1970	6.6822	2.3335	34.9211	.8336	12.4749	3.1671	47.3960	6.6822	2.3335	34.9211	.8336	12.4749	3.1671	47.3960
1971	13.7487	2.8993	21.0878	.9067	11.6167	3.8060	27.6826	20.4309	5.2328	25.6121	1.7403	12.0125	6.9731	34.1301
1972	28.1795	5.5709	19.7693	6.7127	46.3037	12.2836	43.5905	48.6104	10.8037	22.2250	8.4530	29.1639	19.2567	39.6143
1973	16.0278	3.1423	19.6053	2.2778	28.1109	5.4201	33.8168	64.6382	13.9460	21.5754	10.7308	28.9338	24.6768	38.1768
1974	15.6974	3.0549	19.4611	2.1022	25.1197	5.1571	32.8532	80.3356	17.0009	21.1623	12.8330	28.2316	29.8339	37.1365
1975	28.3202	5.3518	18.8974	6.4707	51.9906	11.8225	41.7458	108.6558	22.3527	20.5720	19.3037	33.3386	41.6564	38.3379
1976	13.1747	2.8534	21.6581	2.4447	23.2999	5.2981	40.2141	121.8305	25.2061	20.6894	21.7484	31.7986	46.9545	38.5408
1977	19.6792	3.4076	17.3157	2.7211	16.2387	6.1287	31.1430	141.5097	28.6137	20.2203	24.4695	28.7365	53.0832	37.5120
1978	38.3804	16.9972	44.2861	.5108	12.7572	17.5080	45.6170	179.8901	45.6109	25.3548	24.9803	28.0189	70.5912	39.2412
1979	76.7548	20.7236	26.9997	.5108	12.7572	21.2344	27.6652	256.6449	66.3345	25.8468	25.4911	27.3630	91.8256	35.7792
1980	105.4416	23.5092	22.2959	.5108	12.7572	24.0200	22.7803	362.0865	89.8437	24.8127	26.0019	26.7611	115.8456	31.9939
1981	125.6988	27.0100	21.4878	1.7500	12.4857	28.7600	22.8800	487.7853	116.8537	23.9559	27.7519	24.9614	144.6056	29.6453
1982	76.4508	20.6936	27.0678	.3880	12.7396	21.0816	27.5753	564.2361	137.5473	24.3776	28.1399	24.6355	165.6872	29.3648
1983	127.9152	20.7132	16.1929	2.1250	12.8349	22.8382	17.8541	692.1513	158.2605	22.8650	30.2649	23.1416	188.5254	27.2375
1984	89.1000	15.4480	17.3378	.1224	12.5925	15.5704	17.4751	781.2513	173.7085	22.2346	30.3873	23.0638	204.0958	26.1242
1985	87.7904	15.3208	17.4515	.0696	12.5000	15.3904	17.5308	869.0417	189.0293	21.7514	30.4569	23.0193	219.4862	25.2561

EAST COAST LIQUID HYDROGEN COSTS

MINIMUM REQUIREMENTS OPTION CASE NO. 26
TABLE 1

ESC 1.00000 NEW PLANTS: 1978 1 KSC 170 T/D

YEAR	ANNUAL USAGE MM#	ANNUAL PRODUCTION MM$	ANNUAL PRODUCTION C/#	ANNUAL TRANSPORTATION MM$	ANNUAL TRANSPORTATION C/#	ANNUAL TOTAL MM$	ANNUAL TOTAL C/#	CUMULATIVE USAGE MM#	CUMULATIVE PRODUCTION MM$	CUMULATIVE PRODUCTION C/#	CUMULATIVE TRANSPORTATION MM$	CUMULATIVE TRANSPORTATION C/#	CUMULATIVE TOTAL MM$	CUMULATIVE TOTAL C/#
1970	6.6822	2.3335	34.9211	.8336	12.4749	3.1671	47.3960	6.6822	2.3335	34.9211	.8336	12.4749	3.1671	47.3960
1971	13.7487	2.8993	21.0878	.9067	11.6167	3.8060	27.6826	20.4309	5.2328	25.6121	1.7403	12.0125	6.9731	34.1301
1972	28.1795	5.5709	19.7693	6.7127	46.3037	12.2836	43.5905	48.6104	10.8037	22.2250	8.4530	29.1639	19.2567	39.6143
1973	16.0278	3.1423	19.6053	2.2778	28.1109	5.4201	33.8168	64.6382	13.9460	21.5754	10.7308	28.9338	24.6768	38.1768
1974	15.6974	3.0549	19.4611	2.1022	25.1197	5.1571	32.8532	80.3356	17.0009	21.1623	12.8330	28.2316	29.8339	37.1365
1975	28.3202	5.3518	18.8974	6.4707	51.9906	11.8225	41.7458	108.6558	22.3527	20.5720	19.3037	33.3386	41.6564	38.3379
1976	13.1747	2.8534	21.6581	2.4447	23.2999	5.2981	40.2141	121.8305	25.2061	20.6894	21.7484	31.7986	46.9545	38.5408
1977	19.6792	3.4076	17.3157	2.7211	16.2387	6.1287	31.1430	141.5097	28.6137	20.2203	24.4695	28.7365	53.0832	37.5120
1978	38.3804	18.9788	49.4491	.5108	12.7572	19.4896	50.7800	179.8901	47.5925	26.4564	24.9803	28.0189	72.5728	40.3428
1979	76.7548	22.1140	28.8112	.5108	12.7572	22.6248	29.4767	256.6449	69.7065	27.1606	25.4911	27.3630	95.1976	37.0931
1980	105.4416	24.4576	23.1953	.5108	12.7572	24.9684	23.6798	362.0865	94.1641	26.0059	26.0019	26.7611	120.1660	33.1870
1981	125.6988	27.8868	22.1854	1.7500	12.4857	29.6368	23.5776	487.7853	122.0509	25.0214	27.7519	24.9614	149.8028	30.7108
1982	76.4508	22.0900	28.8944	.3880	12.7396	22.4780	29.4019	564.2361	144.1409	25.5462	28.1399	24.6355	172.2808	30.5334
1983	127.9152	19.4392	15.1969	2.1250	12.8349	21.5642	16.8581	692.1513	163.5801	23.6335	30.2649	23.1416	193.8450	28.0061
1984	89.1000	14.4988	16.2725	.1224	12.5925	14.6212	16.4098	781.2513	178.0789	22.7940	30.3873	23.0638	208.4662	26.6836
1985	87.7904	14.3912	16.3926	.0696	12.5000	14.4608	16.4719	869.0417	192.4701	22.1473	30.4569	23.0193	222.9270	25.6520

EAST COAST LIQUID HYDROGEN COSTS

MINIMUM REQUIREMENTS OPTION CASE NO. 50

TABLE 1

ESC 1.00000 NEW PLANTS: 1972 3 KSC 31 T/D 1979 1 KSC 140 T/D

YEAR	ANNUAL USAGE MM#	ANNUAL PRODUCTION MM$	ANNUAL PRODUCTION C/#	ANNUAL TRANSPORTATION MM$	ANNUAL TRANSPORTATION C/#	ANNUAL TOTAL MM$	ANNUAL TOTAL C/#	CUMULATIVE USAGE MM#	CUMULATIVE PRODUCTION MM$	CUMULATIVE PRODUCTION C/#	CUMULATIVE TRANSPORTATION MM$	CUMULATIVE TRANSPORTATION C/#	CUMULATIVE TOTAL MM$	CUMULATIVE TOTAL C/#
1970	6.6822	2.3335	34.9211	.8336	12.4749	3.1671	47.3960	6.6822	2.3335	34.9211	.8336	12.4749	3.1671	47.3960
1971	13.7487	2.8993	21.0878	.9067	11.6167	3.8060	27.6826	20.4309	5.2328	25.6121	1.7403	12.0125	6.9731	34.1301
1972	28.1794	6.9992	24.8380	1.6075	14.0335	8.6067	30.5425	48.6103	12.2320	25.1633	3.3478	12.9049	15.5798	32.0504
1973	16.0279	8.4845	52.9358	.1829	07.8192	8.6674	54.0769	64.6382	20.7165	32.0499	3.5307	12.4843	24.2472	37.5121
1974	15.6974	8.4517	53.8414	.2240	07.8522	8.6757	55.2683	80.3356	29.1682	36.3079	3.7547	12.0598	32.9229	40.9817
1975	28.3198	9.5475	33.7131	.4774	09.4252	10.0249	35.3989	108.6554	38.7157	35.6316	4.2321	11.6912	42.9478	39.5266
1976	13.1747	8.3478	63.3623	.0897	07.6490	8.4375	64.0432	121.8301	47.0635	38.6304	4.3218	11.5643	51.3853	42.1778
1977	19.6796	6.1328	31.1632	.7460	12.7634	6.8788	34.9539	141.5097	53.1963	37.5919	5.0678	11.7265	58.2641	41.1732
1978	38.3804	8.2372	21.4619	2.0456	12.5570	10.2828	26.7917	179.8901	61.4335	34.1505	7.1134	11.9539	68.5469	38.1048
1979	76.7548	19.5480	25.4681	.5108	12.7572	20.0588	26.1336	256.6449	80.9815	31.5539	7.6242	12.0045	88.6057	34.5246
1980	105.4416	25.4312	24.1187	.5108	12.7572	25.9420	24.6031	362.0865	106.4127	29.3887	8.1350	12.0492	114.5477	31.6354
1981	125.6988	28.9896	23.0627	1.6576	12.3997	30.6472	24.3814	487.7853	135.4023	27.7585	9.7926	12.1071	145.1949	29.7661
1982	76.4508	19.5156	25.5270	.3880	12.7396	19.9036	26.0345	564.2361	154.9179	27.4562	10.1806	12.1301	165.0985	29.2605
1983	127.9152	29.1668	22.8016	2.0316	12.7706	31.1984	24.3899	692.1513	184.0847	26.5960	12.2122	12.2321	196.2969	28.3604
1984	89.1000	15.3588	17.2377	.1224	12.5925	15.4812	17.3750	781.2513	199.4435	25.5287	12.3346	12.2356	211.7781	27.1075
1985	87.7904	15.2204	17.3372	.0696	12.5000	15.2900	17.4164	869.0417	214.6639	24.7012	12.4042	12.2370	227.0681	26.1285

APPENDIX C

COMPUTER SOLUTIONS TO THE

50 LAUNCH OPTION

EAST COAST LIQUID HYDROGEN COSTS

50 LAUNCH OPTION CASE NO. 70

TABLE 1

ESC 1.00000 NEW PLANTS: 1980 1 KSC 60 T/D

YEAR	USAGE MM#	PRODUCTION MM$	PRODUCTION C/#	TRANSPORTATION MM$	TRANSPORTATION C/#	ANNUAL TOTAL MM$	ANNUAL TOTAL C/#	CUMULATIVE USAGE MM#	CUMULATIVE PRODUCTION MM$	CUMULATIVE PRODUCTION C/#	CUMULATIVE TRANSPORTATION MM$	CUMULATIVE TRANSPORTATION C/#	CUMULATIVE TOTAL MM$	CUMULATIVE TOTAL C/#
1970	3.3048	2.0632	62.4304	.4104	12.4183	2.4736	74.8487	3.3048	2.0632	62.4304	.4104	12.4183	2.4736	74.8487
1971	8.3592	2.4680	29.5243	.5000	11.1926	2.9680	35.5057	11.6640	4.5312	38.8477	.9104	11.7078	5.4416	46.6529
1972	13.8024	2.9036	21.0369	.5332	10.6862	3.4368	24.9000	25.4664	7.4348	29.1945	1.4436	11.3085	8.8784	34.8631
1973	8.1000	2.4472	30.2123	.4572	11.0243	2.9044	35.8567	33.5664	9.8820	29.4401	1.9008	11.2388	11.7828	35.1029
1974	7.8408	2.4264	30.9458	.4512	10.8796	2.8776	36.7003	41.4072	12.3084	29.7252	2.3520	11.1680	14.6604	35.4054
1975	14.1912	2.9344	20.6776	.6664	10.6020	3.6008	25.3734	55.5984	15.2428	27.4158	3.0184	11.0379	18.2612	32.8448
1976	6.6096	2.3280	35.2214	.6272	11.9493	2.9552	44.7107	62.2080	17.5708	28.2452	3.6456	11.1847	21.2164	34.1055
1977	5.3136	2.2244	41.8623	.4076	10.6612	2.6320	49.5332	67.5216	19.7952	29.3168	4.0532	11.1297	23.8484	35.3196
1978	8.4240	2.4736	29.3637	.8856	11.8840	3.3592	39.8765	75.9456	22.2688	29.3220	4.9388	11.2579	27.2076	35.8251
1979	14.9040	2.9920	20.0751	1.7644	12.6643	4.7564	31.9135	90.8496	25.2608	27.8050	6.7032	11.5969	31.9640	35.1834
1980	24.6240	9.4436	38.3512	.2468	12.6954	9.6904	39.3534	115.4736	34.7044	30.0539	6.9500	11.6326	41.6544	36.0726
1981	40.4352	11.3572	28.0874	.7716	49.6141	12.1288	29.9956	155.9088	46.0616	29.5439	7.7216	12.5962	53.7832	34.4965
1982	40.4352	11.3572	28.0874	.7716	49.6141	12.1288	29.9956	196.3440	57.4188	29.2439	8.4932	13.5121	65.9120	33.5696
1983	40.1760	11.2988	28.1232	.6428	49.5987	11.9416	29.7232	236.5200	68.7176	29.0536	9.1360	14.2411	77.8536	32.9162
1984	39.3984	11.1236	28.2336	.2564	49.4598	11.3800	28.8844	275.9184	79.8412	28.9365	9.3924	14.5234	89.2336	32.3405
1985	39.1392	8.1072	20.7137	.1280	49.3827	8.2352	21.0407	315.0576	87.9484	27.9150	9.5204	14.6626	97.4688	30.9368

EAST COAST LIQUID HYDROGEN COSTS

50 LAUNCH OPTION CASE NO. 71

TABLE 1

ESC 1.05000 NEW PLANTS: 1980 1 KSC 60 T/D

YEAR	USAGE MM#	PRODUCTION MM$	PRODUCTION C/#	TRANSPORTATION MM$	TRANSPORTATION C/#	ANNUAL TOTAL MM$	ANNUAL TOTAL C/#	CUMULATIVE USAGE MM#	CUMULATIVE PRODUCTION MM$	CUMULATIVE PRODUCTION C/#	CUMULATIVE TRANSPORTATION MM$	CUMULATIVE TRANSPORTATION C/#	CUMULATIVE TOTAL MM$	CUMULATIVE TOTAL C/#
1970	3.3048	2.0681	62.5786	.4180	12.6482	2.4861	75.2269	3.3048	2.0681	62.5786	.4180	12.6482	2.4861	75.2269
1971	8.3592	2.5146	30.0818	.5325	11.9095	3.0471	36.4520	11.6640	4.5827	39.2892	.9505	12.2235	5.5332	47.4382
1972	13.8024	3.0394	22.0208	.5991	12.0069	3.6385	26.3613	25.4664	7.6221	29.9300	1.5496	12.1388	9.1717	36.0149
1973	8.1000	2.5631	31.6432	.5395	13.0087	3.1026	38.3037	33.5664	10.1852	30.3434	2.0891	12.3521	12.2743	36.5672
1974	7.8408	2.5758	32.8512	.5625	13.5633	3.1383	40.0252	41.4072	12.7610	30.8183	2.6516	12.5906	15.4126	37.2220
1975	14.1912	3.2751	23.0783	.8671	13.7950	4.1422	29.1885	55.5984	16.0361	28.8427	3.5187	12.8675	19.5548	35.1715
1976	6.6096	2.5208	38.1384	.8578	16.3427	3.3786	51.1165	62.2080	18.5569	29.8304	4.3765	13.4271	22.9334	36.8656
1977	5.3136	2.4087	45.3308	.5858	15.3222	2.9945	56.3553	67.5216	20.9656	31.0502	4.9623	13.6261	25.9279	38.3994
1978	8.4240	2.8135	33.3986	1.3349	17.9133	4.1484	49.2450	75.9456	23.7791	31.3107	6.2972	14.3543	30.0763	39.6024
1979	14.9040	3.6828	24.7101	2.7517	19.7509	6.4345	43.1729	90.8496	27.4619	30.2278	9.0489	15.6551	36.5108	40.1881
1980	24.6240	15.0525	61.1293	.4109	21.1368	15.4634	62.7980	115.4736	42.5144	36.8174	9.4598	15.8334	51.9742	45.0095
1981	40.4352	18.7655	46.4088	1.3445	86.4519	20.1100	49.7338	155.9088	61.2799	39.3049	10.8043	17.6250	72.0842	46.2348
1982	40.4352	19.3304	47.8058	1.4116	90.7664	20.7420	51.2968	196.3440	80.6103	41.0556	12.2159	19.4347	92.8262	47.2773
1983	40.1760	19.8116	49.3120	1.2351	95.3009	21.0467	52.3862	236.5200	100.4219	42.4581	13.4510	20.9673	113.8729	48.1451
1984	39.3984	20.0761	50.9566	.5183	99.9807	20.5944	52.2721	275.9184	120.4980	43.6716	13.9693	21.6007	134.4673	48.7344
1985	39.1392	16.0501	41.0077	.2717	104.8225	16.3218	41.7019	315.0576	136.5481	43.3406	14.2410	21.9329	150.7891	47.8608

EAST COAST LIQUID HYDROGEN COSTS

50 LAUNCH OPTION CASE NO. 75
TABLE 1

ESC 1.00000 NEW PLANTS: 1980 1 KSC 60 T/D

YEAR	USAGE	PRODUCTION		TRANSPORTATION		ANNUAL TOTAL		CUMULATIVE USAGE	PRODUCTION		TRANSPORTATION		TOTAL	
	MM#	MM$	C/#	MM$	C/#	MM$	C/#	MM#	MM$	C/#	MM$	C/#	MM$	C/#
1970	3.3048	2.0632	62.4304	.4104	12.4183	2.4736	74.8487	3.3048	2.0632	62.4304	.4104	12.4183	2.4736	74.8487
1971	8.3592	2.4680	29.5243	.5000	11.1826	2.9680	35.5057	11.6640	4.5312	38.8477	.9104	11.7078	5.4416	46.6529
1972	13.8024	2.9036	21.0369	.5332	10.6862	3.4368	24.9000	25.4664	7.4348	29.1945	1.4436	11.3085	8.8784	34.8631
1973	8.1000	2.4472	30.2123	.4572	11.0243	2.9044	35.8567	33.5664	9.8820	29.4401	1.9008	11.2388	11.7828	35.1029
1974	7.8408	2.4264	30.9458	.4512	10.8796	2.8776	36.7003	41.4072	12.3084	29.7252	2.3520	11.1680	14.6604	35.4054
1975	14.1912	2.9344	20.6776	.6664	10.6020	3.6008	25.3734	55.5984	15.2428	27.4158	3.0184	11.0379	18.2612	32.8448
1976	6.6096	2.3280	35.2214	.6272	11.9493	2.9552	44.7107	62.2080	17.5708	28.2452	3.6456	11.1847	21.2164	34.1055
1977	5.3136	2.2244	41.8623	.4076	10.6612	2.6320	49.5332	67.5216	19.7952	29.3168	4.0532	11.1297	23.8484	35.3196
1978	8.4240	2.4736	29.3637	.8856	11.8840	3.3592	39.8765	75.9456	22.2688	29.3220	4.9388	11.2579	27.2076	35.8251
1979	14.9040	2.9920	20.0751	1.7644	12.6643	4.7564	31.9135	90.8496	25.2608	27.8050	6.7032	11.5969	31.9640	35.1834
1980	24.6240	9.8252	39.9009	.2468	12.6954	10.0720	40.9031	115.4736	35.0860	30.3844	6.9500	11.6326	42.0360	36.4031
1981	40.4352	11.7200	28.9846	.7716	49.6141	12.4916	30.8928	155.9088	46.8060	30.0213	7.7216	12.5962	54.5276	34.9740
1982	40.4352	11.7200	28.9846	.7716	49.6141	12.4916	30.8928	196.3440	58.5260	29.8078	8.4932	13.5121	67.0192	34.1335
1983	40.1760	11.6616	29.0262	.6428	49.5987	12.3044	30.6262	236.5200	70.1876	29.6751	9.1360	14.2411	79.3236	33.5377
1984	39.3984	11.4864	29.1544	.2564	49.4598	11.7428	29.8052	275.9184	81.6740	29.6007	9.3924	14.5234	91.0664	33.0048
1985	39.1392	8.0324	20.5226	.1280	49.3827	8.1604	20.8496	315.0576	89.7064	28.4730	9.5204	14.6626	99.2268	31.4948

APPENDIX D

COMPUTER SOLUTIONS TO THE REVISED MINIMUM REQUIREMENTS OPTION

EAST COAST LIQUID HYDROGEN COSTS — REVISED MINIMUM REQUIREMENTS OPTION — CASE NO. 81

TABLE 1

ESC 1.00000 NEW PLANTS: 1991 1 KSC 60 T/D

YEAR	USAGE MM#	PRODUCTION MM$	PRODUCTION C/#	TRANSPORTATION MM$	TRANSPORTATION C/#	TOTAL MM$	ANNUAL C/#	CUMULATIVE USAGE MM#	PRODUCTION MM$	PRODUCTION C/#	TRANSPORTATION MM$	TRANSPORTATION C/#	TOTAL MM$	C/#
1971	4.3655	2.1482	49.2085	.4333	09.9255	2.5815	59.1341	4.3655	2.1482	49.2085	.4333	09.9255	2.5815	59.1341
1972	14.3252	2.9451	20.5588	1.5346	10.7125	4.4797	31.2714	18.6907	5.0933	27.2504	1.9679	10.5287	7.0612	37.7792
1973	19.3765	3.4080	17.5883	2.2941	11.8395	5.7021	29.4279	38.0672	8.5013	22.3323	4.2620	11.1959	12.7633	33.5283
1974	19.9288	3.5383	17.7547	2.5262	12.6761	6.0645	30.4308	57.9960	12.0396	20.7593	6.7882	11.7046	18.8278	32.4639
1975	21.1193	4.3939	20.8051	5.3860	33.9508	9.7799	46.3078	79.1153	16.4335	20.7715	12.1742	16.4827	28.6077	36.1595
1976	36.2435	7.6193	21.0225	15.3950	58.1849	23.0143	63.4991	115.3588	24.0528	20.8504	27.5692	27.4815	51.6220	44.7490
1977	6.0648	2.2840	37.6590	3.5092	57.8617	5.7932	95.5216	121.4236	26.3368	21.6900	31.0784	29.2134	57.4152	47.2850
1978	13.0632	2.8440	21.7710	4.3860	33.5752	7.2300	55.3463	134.4868	29.1808	21.6978	35.4644	29.6905	64.6452	48.0680
1979	14.6056	2.9676	20.3182	4.5792	31.3523	7.5468	51.6705	149.0924	32.1484	21.5627	40.0436	29.8715	72.1920	48.4209
1980	19.7764	3.4296	17.3418	4.7912	24.2268	8.2208	41.5687	168.8688	35.5780	21.0684	44.8348	29.1458	80.4128	47.6185
1981	23.7748	9.3512	39.3324	.3276	12.9979	9.6788	40.7103	192.6436	44.9292	23.3224	45.1624	28.8855	90.0916	46.7659
1982	30.7664	10.1180	32.8865	.3276	12.9979	10.4456	33.9513	223.4100	55.0472	24.6395	45.4900	28.6335	100.5372	45.0012
1983	37.7648	10.8856	28.8247	.3276	12.9979	11.2132	29.6922	261.1748	65.9328	25.2447	45.8176	28.3893	111.7504	42.7875
1984	44.7632	13.2776	29.6618	.6192	10.5248	13.8968	31.0451	305.9380	79.2104	25.8909	46.4368	27.7610	125.6472	41.0694
1985	51.7616	13.8376	26.7333	1.5404	11.9581	15.3780	29.7092	357.6996	93.0480	26.0128	47.9772	26.6310	141.0252	39.4255
1986	57.2568	11.3192	19.7691	2.3140	12.5919	13.6332	23.8106	414.9564	104.3672	25.1513	50.2912	25.3315	154.6584	37.2710

EAST COAST LIQUID HYDROGEN COSTS — REVISED MINIMUM REQUIREMENTS OPTION — CASE NO. 85

TABLE 1

ESC 1.00000 NEW PLANTS: 1973 1 KSC 60 T/D

YEAR	USAGE MM#	PRODUCTION MM$	PRODUCTION C/#	TRANSPORTATION MM$	TRANSPORTATION C/#	TOTAL MM$	ANNUAL C/#	CUMULATIVE USAGE MM#	PRODUCTION MM$	PRODUCTION C/#	TRANSPORTATION MM$	TRANSPORTATION C/#	TOTAL MM$	C/#
1971	4.3655	2.1482	49.2085	.4333	09.9255	2.5815	59.1341	4.3655	2.1482	49.2085	.4333	09.9255	2.5815	59.1341
1972	14.3252	2.9451	20.5588	1.5346	10.7125	4.4797	31.2714	18.6907	5.0933	27.2504	1.9679	10.5287	7.0612	37.7792
1973	19.3766	8.8685	45.7691	1.2874	13.1138	10.1559	52.4132	38.0673	13.9618	36.6766	3.2553	11.4189	17.2171	45.2280
1974	19.9289	8.9297	44.8052	1.6799	13.4220	10.6091	53.2347	57.9962	22.8910	39.4698	4.9352	12.0300	27.8262	47.9793
1975	21.1194	9.4006	44.5116	.5761	12.0598	9.9767	47.2395	79.1156	32.2916	40.8157	5.5113	12.0331	37.8029	47.7818
1976	36.2437	11.7208	32.3388	.2296	09.1096	11.9504	32.9723	115.3593	44.0124	38.1524	5.7409	11.8807	49.7533	43.1289
1977	6.0648	7.4084	122.1540	.3276	12.9979	7.7360	127.5557	121.4241	51.4208	42.3481	6.0685	11.9360	57.4893	47.3458
1978	13.0632	5.2180	39.9442	.3276	12.9979	5.5456	42.4520	134.4873	56.6388	42.1146	6.3961	11.9862	63.0349	46.8705
1979	14.6056	5.3872	36.8844	.3276	12.9979	5.7148	39.1274	149.0929	62.0260	41.6022	6.7237	12.0318	68.7497	46.1119
1980	19.7764	5.9544	30.1086	.3276	12.9979	6.2820	31.7651	168.8693	67.9804	40.2562	7.0513	12.0735	75.0317	44.4318
1981	23.7748	6.3932	26.8906	.3276	12.9979	6.7208	28.2685	192.6441	74.3736	38.6067	7.3789	12.1118	81.7525	42.4370
1982	30.7664	7.1600	23.2721	.3276	12.9979	7.4876	24.3369	223.4105	81.5336	36.4949	7.7065	12.1470	89.2401	39.9444
1983	37.7648	7.9276	20.9920	.3276	12.9979	8.2552	21.8595	261.1753	89.4612	34.2533	8.0341	12.1795	97.4953	37.3294
1984	44.7632	10.3196	23.0537	.6192	10.5248	10.9388	24.4370	305.9385	99.7808	32.6146	8.6533	12.0440	108.4341	35.4431
1985	51.7616	10.8796	21.0186	1.5404	11.9581	12.4200	23.9946	357.7001	110.6604	30.9366	10.1937	12.0309	120.8541	33.7864
1986	57.2568	11.3192	19.7691	2.3140	12.5919	13.6332	23.8106	414.9569	121.9796	29.3957	12.5077	12.1309	134.4873	32.4099

EAST COAST LIQUID HYDROGEN COSTS — REVISED MINIMUM REQUIREMENTS OPTION — CASE NO. 83

TABLE 1

ESC 1.00000 NEW PLANTS: 1975 4 KSC 60 T/D

YEAR	USAGE MM#	PRODUCTION MM$	PRODUCTION C/#	TRANSPORTATION MM$	TRANSPORTATION C/#	TOTAL MM$	ANNUAL TOTAL C/#	CUMULATIVE USAGE MM#	PRODUCTION MM$	PRODUCTION C/#	TRANSPORTATION MM$	TRANSPORTATION C/#	TOTAL MM$	TOTAL C/#
1971	4.3655	2.1482	49.2085	.4333	09.9255	2.5815	59.1341	4.3655	2.1482	49.2085	.4333	09.9255	2.5815	59.1341
1972	14.3252	2.9451	20.5588	1.5346	10.7125	4.4797	31.2714	18.6907	5.0933	27.2504	1.9679	10.5287	7.0612	37.7792
1973	19.3765	3.4080	17.5893	2.2941	11.8395	5.7021	29.4279	38.0672	8.5013	22.3323	4.2620	11.1959	12.7633	33.5283
1974	19.9288	3.5383	17.7547	2.5262	12.6761	6.0645	30.4308	57.9960	12.0396	20.7593	6.7882	11.7046	18.8278	32.4639
1975	21.1194	5.3964	25.5518	.9380	11.1849	6.3344	29.9932	79.1154	17.4360	22.0386	7.7262	11.6389	25.1622	31.8044
1976	36.2437	11.7208	32.3388	.2296	09.1096	11.9504	32.9723	115.3591	29.1568	25.2748	7.9558	11.5464	37.1126	32.1713
1977	6.0648	7.4084	122.1540	.3276	12.9979	7.7360	127.5557	121.4239	36.5652	30.1136	8.2834	11.5976	44.8486	36.9355
1978	13.0632	8.1760	62.5880	.3276	12.9979	8.5036	65.0958	134.4871	44.7412	33.2680	8.6110	11.6453	53.3522	39.6708
1979	14.6056	8.3452	57.1369	.3276	12.9979	8.6728	59.3799	149.0927	53.0864	35.6063	8.9386	11.6899	62.0250	41.6016
1980	19.7764	8.1729	41.3265	.3276	12.9979	8.5005	42.9830	168.8691	61.2593	36.2762	9.2662	11.7316	70.5255	41.7634
1981	23.7748	6.3932	26.8906	.3276	12.9979	6.7208	28.2685	192.6439	67.6525	35.1179	9.5938	11.7708	77.2463	40.0979
1982	30.7664	7.1600	23.2721	.3276	12.9979	7.4876	24.3369	223.4103	74.8125	33.4865	9.9214	11.8076	84.7339	37.9274
1983	37.7648	7.9276	20.9920	.3276	12.9979	8.2552	21.8595	261.1751	82.7401	31.6799	10.2490	11.8423	92.9891	35.6041
1984	44.7632	10.3196	23.0537	.6192	10.5248	10.9388	24.4370	305.9383	93.0597	30.4177	10.8682	11.7584	103.9279	33.9702
1985	51.7616	10.8796	21.0186	1.5404	11.9581	12.4200	23.9946	357.6999	103.9393	29.0576	12.4086	11.7828	116.3479	32.5266
1986	57.2568	11.3192	19.7691	2.3140	12.5919	13.6332	23.8106	414.9567	115.2585	27.7760	14.7226	11.9031	129.9811	31.3240

EAST COAST LIQUID HYDROGEN COSTS — REVISED MINIMUM REQUIREMENTS OPTION — CASE NO. 84

TABLE 1

ESC 1.05000 NEW PLANTS: 1975 4 KSC 60 T/D

YEAR	USAGE MM#	PRODUCTION MM$	PRODUCTION C/#	TRANSPORTATION MM$	TRANSPORTATION C/#	TOTAL MM$	ANNUAL TOTAL C/#	CUMULATIVE USAGE MM#	PRODUCTION MM$	PRODUCTION C/#	TRANSPORTATION MM$	TRANSPORTATION C/#	TOTAL MM$	TOTAL C/#
1971	4.3655	2.1545	49.3528	.4410	10.1019	2.5955	59.4548	4.3655	2.1545	49.3528	.4410	10.1019	2.5955	59.4548
1972	14.3252	3.0296	21.1487	1.6438	11.4748	4.6734	32.6236	18.6907	5.1841	27.7362	2.0848	11.1542	7.2689	38.8904
1973	19.3765	3.6039	18.5993	2.5549	13.1855	6.1588	31.7848	38.0672	8.7880	23.0854	4.6397	12.1881	13.4277	35.2736
1974	19.9288	3.8532	19.3348	2.9595	14.8503	6.8127	34.1851	57.9960	12.6412	21.7966	7.5992	13.1029	20.2404	34.8996
1975	21.1194	6.2210	29.4563	1.1545	13.7665	7.3755	34.9228	79.1154	18.8622	23.8413	8.7537	13.1867	27.6159	34.9058
1976	36.2437	14.2529	39.3251	.3004	11.9187	14.5533	40.1540	115.3591	33.1151	28.7061	9.0541	13.1404	42.1692	36.5547
1977	6.0648	9.2415	152.3793	.4478	17.7670	9.6893	159.7628	121.4239	42.3566	34.8832	9.5019	13.3036	51.8585	42.7086
1978	13.0632	10.5149	80.4925	.4702	18.6557	10.9851	84.0919	134.4871	52.8715	39.3134	9.9721	13.4861	62.8436	46.7283
1979	14.6056	11.0065	75.3580	.4939	19.5960	11.5004	78.7396	149.0927	63.8780	42.8444	10.4660	13.6875	74.3440	49.8642
1980	19.7764	11.2870	57.0730	.5188	20.5840	11.8058	59.6964	168.8691	75.1650	44.5108	10.9848	13.9075	86.1498	51.0157
1981	23.7748	9.7023	40.8091	.5447	21.6116	10.2470	43.1002	192.6439	84.8673	44.0539	11.5295	14.1458	96.3968	50.0388
1982	30.7664	11.4100	37.0859	.5720	22.6948	11.9820	38.9450	223.4103	96.2773	43.0943	12.1015	14.4022	108.3788	48.5111
1983	37.7648	13.2712	35.1417	.6007	23.8335	13.8719	36.7323	261.1751	109.5485	41.9444	12.7022	14.6769	122.2507	46.8079
1984	44.7632	16.7593	37.4399	1.1927	20.2729	17.9520	40.1043	305.9383	126.3078	41.2853	13.8949	15.0331	140.2027	45.8271
1985	51.7616	18.5230	35.7852	3.0655	23.7975	21.5885	41.7075	357.6999	144.8308	40.4894	16.9604	16.1051	161.7912	45.2309
1986	57.2568	20.1765	35.2386	4.7595	25.8995	24.9360	43.5511	414.9567	165.0073	39.7649	21.7199	17.5603	186.7272	44.9992

EAST COAST LIQUID HYDROGEN COSTS — REVISED MINIMUM REQUIREMENTS OPTION — CASE NO. 86

TABLE 1

ESC 1.00000 NEW PLANTS: 1975 4 KSC 60 T/D

YEAR	ANNUAL USAGE MM#	ANNUAL PRODUCTION MM$	ANNUAL PRODUCTION C/#	ANNUAL TRANSPORTATION MM$	ANNUAL TRANSPORTATION C/#	ANNUAL TOTAL MM$	ANNUAL TOTAL C/#	CUMULATIVE USAGE MM#	CUMULATIVE PRODUCTION MM$	CUMULATIVE PRODUCTION C/#	CUMULATIVE TRANSPORTATION MM$	CUMULATIVE TRANSPORTATION C/#	CUMULATIVE TOTAL MM$	CUMULATIVE TOTAL C/#
1971	4.3655	2.1482	49.2085	.4333	09.9255	2.5815	59.1341	4.3655	2.1482	49.2085	.4333	09.9255	2.5815	59.1341
1972	14.3252	2.9451	20.5588	1.5346	10.7125	4.4797	31.2714	18.6907	5.0933	27.2504	1.9679	10.5287	7.0612	37.7792
1973	19.3765	3.4080	17.5883	2.2941	11.8395	5.7021	29.4279	38.0672	8.5013	22.3323	4.2620	11.1959	12.7633	33.5283
1974	19.9288	3.5383	17.7547	2.5262	12.6761	6.0645	30.4308	57.9960	12.0396	20.7593	6.7882	11.7046	18.8278	32.4639
1975	21.1194	5.4917	26.0031	.9380	11.1849	6.4297	30.4445	79.1154	17.5313	22.1591	7.7262	11.6389	25.2575	31.9248
1976	36.2437	12.1079	33.4069	.2296	09.1096	12.3375	34.0603	115.3591	29.6392	25.6929	7.9558	11.9464	37.5950	32.5895
1977	6.0648	7.0148	128.8550	.3276	12.9979	8.1424	134.2566	121.4239	37.4540	30.8456	8.2834	11.5976	45.7374	37.6675
1978	13.0632	8.5752	65.6439	.3276	12.9979	8.9028	68.1517	134.4871	46.0292	34.2257	8.6110	11.6453	54.6402	40.6285
1979	14.6056	8.7628	59.8592	.3276	12.9979	9.0704	62.1022	149.0927	54.7720	36.7368	8.9386	11.6899	63.7106	42.7322
1980	19.7764	8.4555	42.7555	.3276	12.9979	8.7831	44.4120	168.8691	63.2275	37.4417	9.2662	11.7316	72.4937	42.9289
1981	23.7748	6.3432	26.6803	.3276	12.9979	6.6708	28.0582	192.6439	69.5707	36.1136	9.5938	11.7708	79.1645	41.0936
1982	30.7664	7.1028	23.0862	.3276	12.9979	7.4304	24.1510	223.4103	76.6735	34.3195	9.9214	11.8076	86.5949	38.7604
1983	37.7648	7.8632	20.8215	.3276	12.9979	8.1908	21.6889	261.1751	84.5367	32.3678	10.2490	11.8423	94.7857	36.2920
1984	44.7632	10.2540	22.9072	.6192	10.5248	10.8732	24.2904	305.9383	94.7907	30.9836	10.8682	11.7584	105.6589	34.5360
1985	51.7616	10.8140	20.8919	1.5404	11.9581	12.3544	23.8678	357.6999	105.6047	29.5232	12.4086	11.7828	118.0133	32.9922
1986	57.2568	11.2536	19.6546	2.3140	12.5919	13.5676	23.6960	414.9567	116.8583	28.1615	14.7226	11.9031	131.5809	31.7095

EAST COAST LIQUID HYDROGEN COSTS — REVISED MINIMUM REQUIREMENTS OPTION — CASE NO. 88

TABLE 1

ESC 1.00000 NEW PLANTS: 1975 4 KSC 90 T/D

YEAR	ANNUAL USAGE MM#	ANNUAL PRODUCTION MM$	ANNUAL PRODUCTION C/#	ANNUAL TRANSPORTATION MM$	ANNUAL TRANSPORTATION C/#	ANNUAL TOTAL MM$	ANNUAL TOTAL C/#	CUMULATIVE USAGE MM#	CUMULATIVE PRODUCTION MM$	CUMULATIVE PRODUCTION C/#	CUMULATIVE TRANSPORTATION MM$	CUMULATIVE TRANSPORTATION C/#	CUMULATIVE TOTAL MM$	CUMULATIVE TOTAL C/#
1971	4.3655	2.1482	49.2085	.4333	09.9255	2.5815	59.1341	4.3655	2.1482	49.2085	.4333	09.9255	2.5815	59.1341
1972	14.3252	2.3451	20.5588	1.5346	10.7125	4.4797	31.2714	18.6907	5.0933	27.2504	1.9679	10.5287	7.0612	37.7792
1973	19.3765	3.4080	17.5883	2.2941	11.8395	5.7021	29.4279	38.0672	8.5013	22.3323	4.2620	11.1959	12.7633	33.5283
1974	19.9288	3.5383	17.7547	2.5262	12.6761	6.0645	30.4308	57.9960	12.0396	20.7593	6.7882	11.7046	18.8278	32.4639
1975	21.1194	5.5294	26.1816	1.3657	11.9957	6.8951	32.6481	79.1154	17.5690	22.2068	8.1539	11.7523	25.7229	32.5131
1976	36.2437	12.6441	34.8863	1.6232	13.1912	14.2673	39.3649	115.3591	30.2131	26.1904	9.7771	11.9691	39.9902	34.6658
1977	6.0648	9.4103	155.1708	.3276	12.9979	9.7384	160.5724	121.4239	39.6239	32.6327	10.1047	11.9999	49.7286	40.9545
1978	13.0632	10.1604	77.7787	.3276	12.9979	10.4880	80.2866	134.4871	49.7843	37.0178	10.4323	12.0289	60.2166	44.7750
1979	14.6056	10.3260	70.6989	.3276	12.9979	10.6536	72.9418	149.0927	60.1103	40.3173	10.7599	12.0562	70.8702	47.5343
1980	19.7764	9.8344	49.7279	.3276	12.9979	10.1620	51.3844	168.8691	69.9447	41.4194	11.0875	12.0821	81.0322	47.9852
1981	23.7748	7.1255	29.9712	.3276	12.9979	7.4532	31.3491	192.6439	77.0703	40.0066	11.4151	12.1066	88.4854	45.9321
1982	30.7664	7.8748	25.5954	.3276	12.9979	8.2024	26.6602	223.4103	84.9451	38.0220	11.7427	12.1298	96.6878	43.2781
1983	37.7648	8.6249	22.6381	.3276	12.9979	8.9524	23.7056	261.1751	93.5699	35.8265	12.0703	12.1518	105.6402	40.4480
1984	44.7632	9.3744	20.9422	.3276	12.9979	9.7020	21.6740	305.9383	102.9443	33.6487	12.3979	12.1728	115.3422	37.7011
1985	51.7616	10.1244	19.5596	.3276	12.9979	10.4520	20.1925	357.6999	113.0587	31.6099	12.7255	12.1927	125.7942	35.1675
1986	57.2568	10.7137	18.7107	.3276	12.9979	11.0408	19.2829	414.9567	123.7819	29.8300	13.0531	12.2117	136.8350	32.9757